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ENERGY FACT BOOK

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PREPARED UNDER THE DIRECTION OF THE DIRECTOR, NAVY ENERGY AND NATURAL RESOURCES RESEARCH AND DEVELOPMENT OFFICE

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The Department of the Navy Energy Fact Book presents the U.S., including the DOD and Navy, energy situation; summarizes Navy energy R&D initiatives; provides an in-depth description of the various processes and developments related to hydrocarbon fuels, synthetic fuels, non-hydrocarbon energy sources, and energy conversion; and briefly describes energy R&D legislation and cooperative energy programs.

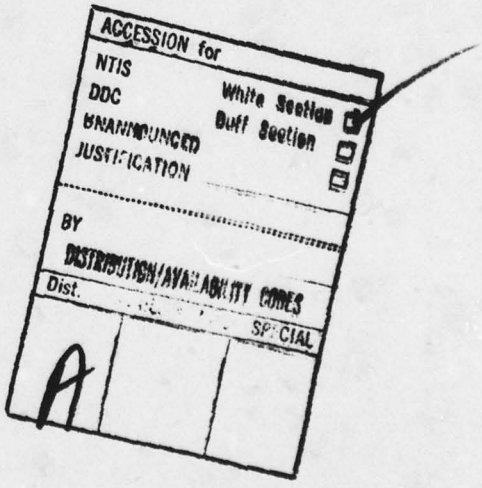
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FOREWORD

This Department of the Navy *Energy Fact Book*, prepared under the direction of the Director, Navy Energy and Natural Resources Research and Development Office, is intended as a supporting document to the Navy energy research and development programs in energy conservation, synthetic fuels, and energy self-sufficiency. The Navy is adapting applicable energy technologies and technical procedures to reduce fuel consumption while maintaining the required readiness and operational effectiveness. The Navy's energy technology activities designed to alleviate some of its fuel problems and aid in the development of a capability to use alternative energy sources are summarized in this *Energy Fact Book*, and the most important energy supply and conversion technologies available to all sectors of the U.S. economy are discussed in detail.



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Appendix A—Government Activities

Appendix B—Energy Conversion Factors

1. ENERGY AND THE NAVY

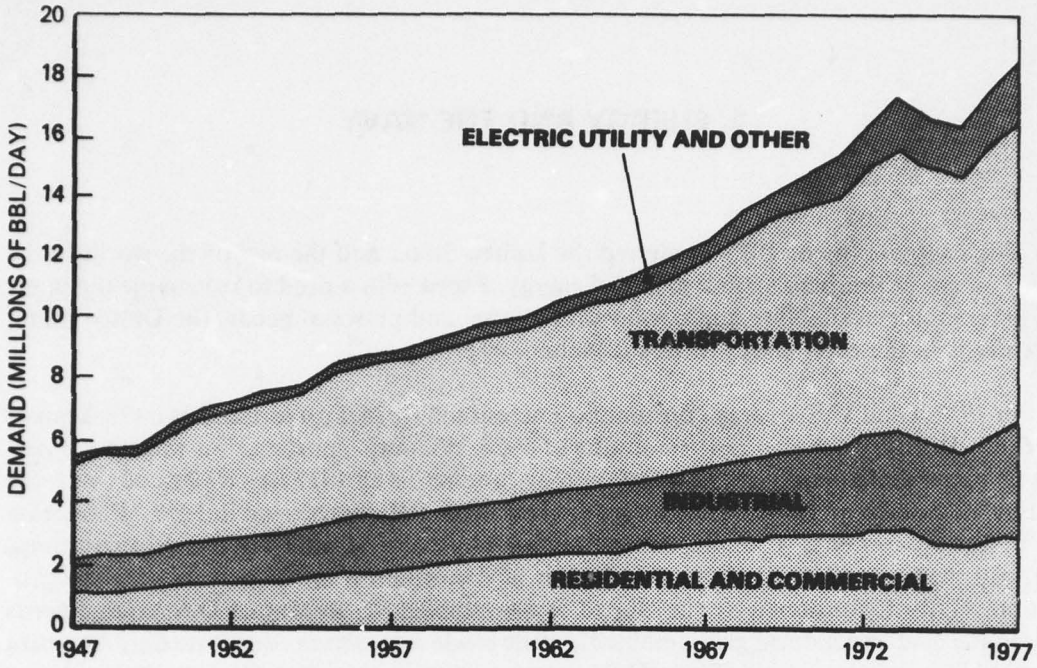
The energy crisis of 1973-74 alerted the United States and the rest of the world to the end of an era of inexpensive and plentiful energy. Faced with a need to reexamine the interplay of resource availability and costs with national and personal needs, the United States currently is in the early stages of this reevaluation effort.

In 1977, total U.S. energy consumption amounted to 76.3 quadrillion Btu (76.3 quads or 76.3×10^{15} Btu); for the first 10 months of 1978, domestic consumption was up 2.3 percent from the same period in 1977. U.S. energy production in 1977 was 60.2 quads and, for the first 10 months of 1978, was down 0.5 percent from the same period in 1977.[1] Petroleum has been the major energy source, accounting for 44 percent of total world energy consumption, and the United States has been the major oil consumer, using 29 percent of world production.[2] The oil consumed by the United States supplies 48 percent of U.S. energy needs (more than coal and natural gas combined), while crude oil reserves constitute only 4 percent of total U.S. energy reserves. Thus, U.S. energy problems are primarily a result of this imbalance in petroleum supply and demand.

Figure 1-1 shows the domestic demand for refined petroleum products by end-use sector since 1947. While all sectors of the U.S. economy rely heavily on energy from petroleum, the transportation sector, which depends almost completely on liquid petroleum fuels, consumes more than half of the petroleum products used in the United States.

National security/defense depends heavily on the availability of energy in all forms, especially mobility fuels, to support worldwide commitments on the seas, in the air, and on the ground. The Department of Defense (DOD) is the largest single U.S. energy consumer and accounts for about 2 percent of the national energy consumption through direct usage; the energy consumption level for both DOD and related industries amounts to 5 percent of overall national energy use.[3] The use of energy sources other than petroleum and natural gas wherever possible is important because it could serve to release, for transportation and defense-related operations, the liquid petroleum for which there is presently no substitute.

This chapter summarizes the U.S. energy outlook and describes the Department of the Navy energy technology activities designed to alleviate some of its fuel problems and aid in the development of a capability to use alternative energy sources. The remainder of this *Energy Fact Book* discusses in detail the most important energy supply and conversion technologies available to all sectors of the U.S. economy, including manufacturing, residential and commercial energy needs, and electrical utilities.



Source: U.S. Department of the Interior, Bureau of Mines, and U.S. Department of Energy, Energy Information Administration.

Figure 1-1. DOMESTIC DEMAND FOR REFINED PETROLEUM PRODUCTS BY END-USE SECTOR

U.S. ENERGY OUTLOOK

At the present time, U.S. energy consumption significantly outstrips production capacity. Tables 1-1 and 1-2 show U.S. energy consumption and production by energy source for 1977. About 20 percent of total U.S. energy requirements and nearly 50 percent of petroleum requirements is being met through the use of imported oil. It is generally agreed that if the United States is to maintain the growth of its standard of living and position in foreign affairs, energy demands will continue to increase. The rate of increase, however, is predicted to be much less than that during the 1960s and early 1970s. Among the factors responsible for this slowdown are the 1973-74 oil crisis, increasing energy prices, and government conservation policies and public awareness programs. Market saturation for some large energy-consuming items, such as automobiles and air conditioners, and development of new energy-saving technologies have also contributed. Although the overall energy demand is expected to continue to grow, strong economic and governmental pressures will materially influence energy utilization patterns in the various consumption sectors, including residential, commercial, industrial, transportation, and electric power generation. Energy consumption by sector for 1977 is shown in Table 1-3. In general, the trends will be away from the use of oil and natural gas, which are in short supply, and toward the use of coal and inexhaustible energy sources such as solar, hydro, and wind power.

Table 1-1. U.S. ENERGY CONSUMPTION, 1977

Energy Source	Quads	Percent Demand
Petroleum	36.947	48
Natural gas (dry)	19.931	26
Coal	14.133	19
Hydroelectric power	2.511	3
Nuclear electric power	2.674	4
Geothermal power and other	0.103	<1
Total	76.299	100

Source: U.S. Department of Energy, "Monthly Energy Review," DOE/EIA/0035/1(79), January 1979.

Table 1-2. U.S. ENERGY PRODUCTION, 1977

Energy Source	Quads	Percent Demand
Crude oil	17.315	29
Natural gas (dry)	19.565	33
Coal	15.926	26
Natural gas plant liquids	2.323	4
Hydroelectric power	2.331	4
Nuclear electric power	2.674	4
Geothermal power and other	0.088	<1
Total	60.223	100

Source: U.S. Department of Energy, "Monthly Energy Review," DOE/EIA/0035/1(79), January 1979.

Table 1-3. ENERGY CONSUMPTION BY SECTOR, 1977

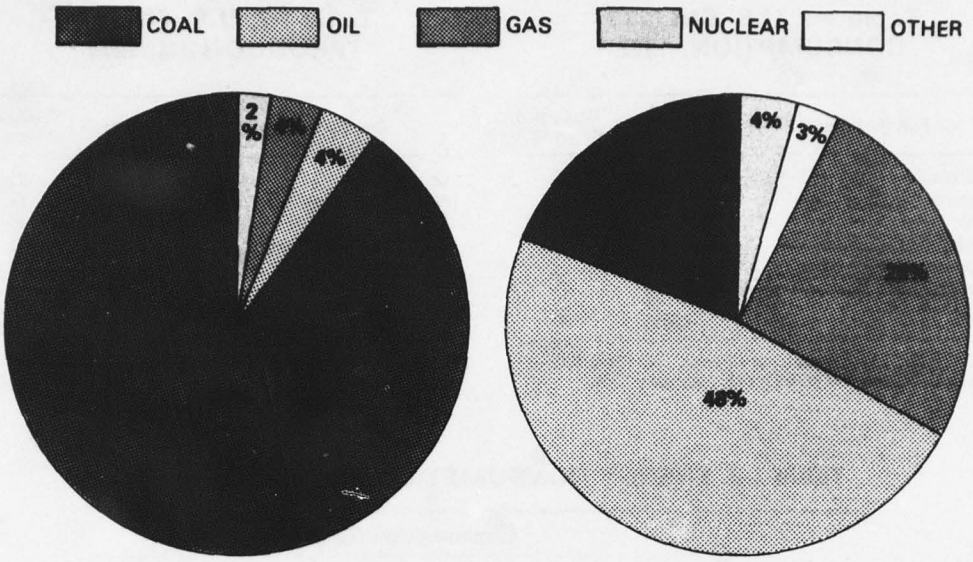
Energy Type	Consumption (Quadrillion Btu)		
	Industrial	Residential and Commercial	Transportation
Petroleum	6.917	7.114	19.094
Natural gas (dry)	8.547	7.500	0.599
Coal	3.577	0.246	Negligible
Hydropower	0.036	—	—
Electricity	2.636	3.883	0.064
Electrical energy loss[a]	6.443	9.487	0.156
Total energy use	28.156	28.231	19.913

[a]In generating electricity with nuclear or fossil fuels, about 65 percent of the energy is lost in the form of heat and about 3 percent is lost during transmission and distribution. To account fully for ultimate energy disposition, electricity losses are allocated to the final end-use sectors in proportion to their direct kilowatt-hour usage.

Source: U.S. Department of Energy, "Monthly Energy Review," DOE/EIA/0035/1(79), January 1979.

Figure 1-2 shows the basis of the U.S. energy problem. Coal comprises 90 percent of the total U.S. proved reserves, yet supplies only 19 percent of U.S. energy needs. Seventy-four percent of the U.S. energy needs are now met by oil and natural gas, even though these energy sources account for only about 8 percent of U.S. energy reserves.[1]

U.S. oil production has declined from its 1970 peak, although recent drilling activity and the first deliveries of oil from the Alaskan North Slope have arrested the decline for the near term. The increase in U.S. oil production in 1977 was due entirely to Alaskan North Slope output, which began in mid-1977 and reached its current capacity of 1.2 million bbl/day in early 1978.[4] Total domestic crude oil production was about 3.0 billion bbl in 1977,[4] while domestic consumption was 6.5 billion bbl.[2] Crude imports have been increasing rapidly since 1971, reflecting both the rise in domestic demand for petroleum products and the pre-1977 decline in U.S. production. Imports from member countries of the Organization of Petroleum Exporting Countries have been increasing at an average annual rate of 24 percent since 1970, and comprised 70.5 percent of total U.S. oil imports in 1977.[1]



Source: U.S. Department of Energy, "Monthly Energy Review," DOE/EIA/0035/1(79), January 1979.

Figure 1-2. SOURCES OF THE U.S. ENERGY PROBLEM

Natural gas is used heavily by industry and in the residential and commercial sectors, comprising 26 percent of 1977 U.S. energy consumption.[1,2] Domestic gas production peaked at 22.2 trillion cubic feet (tcf) in 1973, and in 1977, 19.5 tcf were produced, a 1.7 percent increase from the 1976 level.[5,6] U.S. natural gas consumption was about 19.6 tcf in 1977, a 4.3 percent decrease from the 1976 level. The opportunities for supplementing domestic production of natural gas with imports are few. Gas is far more expensive than oil to transport overseas because it must be liquefied before shipping, then regasified at its destination. Consequently, natural gas imports can only supplement dwindling domestic energy sources.

The ways in which the United States can decrease its dependence on oil and natural gas—in addition to an increased reliance on coal—include energy conservation and the greater use of alternative energy sources. Energy conservation involves not only the reduction of energy demand, but also increased efficiency in production and utilization. Primary oil recovery typically recovers less than one-third of the oil reserves and room-and-pillar coal mining leaves 40 to 50 percent of the coal in the mine as roof and wall supports.[7] U.S. coal production could expand significantly, but the mining and burning of coal create environmental problems, whereas oil and natural gas are cleaner burning and easier to handle. Further, electric utility plants require 3 bbl of oil to generate 1 bbl of oil equivalent (BOE) of electricity. In short, the economy makes use of only a small part of the resources it taps. Many of the new conservation strategies and policies will have to be directed toward improving these efficiencies.

The United States will have to decide between increasing oil-import vulnerability and changing energy consumption patterns while developing energy alternatives to the use of petroleum and natural gas. Most of the energy consumed between now and 1990 will be supplied from the oil wells, gas fields, and coal mines that are currently serving the country. Experience has shown that considerable lead time (8 to 13 years) is required to develop new energy sources from concept to field use, but, in the long term, many options appear promising. The alternatives to using petroleum, natural gas, and coal include increased use of nuclear and hydropower for electricity production; further development and use of geothermal, solar, wind, and ocean resources; and production of synthetic fuels from such sources as coal, oil shale, tar sands, and biomass.

Although development of these energy sources is progressing, they involve technological and economic uncertainties as well as environmental problems (see Table 1-4). In addition, several of these technologies can be applied only in particular geographic areas, further limiting their potential to ease the burden now carried by petroleum and natural gas. Until these technologies are further developed, then—through the 1980s, at least—primary reliance for energy will be on the conventional sources currently utilized.

Table 1-4. BARRIERS TO DEVELOPING ALTERNATIVE ENERGY SOURCES

Technology	Issues and Areas of Uncertainty
Enhanced oil and gas recovery	Federal oil and gas pricing policies
Synthetic liquids and gases and direct utilization of coal	Federal energy policy Disposal of spent material Water consumption Strip mining and reclamation Sulfur oxide standards World oil prices Capital requirements
Geothermal	Lack of comprehensive resource information Lack of proved domestic technology Legal and regulatory complexities
Light water reactors	Limited uranium reserves
Liquid metal fast breeder reactors	Economic uncertainty Safety Radioactive waste management Insufficient engineering base (breeders) Fuel cycle performance (breeders)
Solar heating and cooling	Economic uncertainty Limited geographic applicability Need for conventional backup Legal complexities
Solar electric Solar thermal electric Solar photovoltaic Wind energy Ocean thermal energy conversion	Economic uncertainty Legal complexities Lack of proved technology
Fusion	Very early in the development cycle

Source: U.S. Energy Research and Development Administration, "Creating Energy Choices for the Future," 1976.

NAVY ENERGY TECHNOLOGY ACTIVITIES

As do other sectors of the U.S. economy, DOD and the Department of the Navy rely on conventional energy sources—primarily liquid hydrocarbon fuels derived from petroleum. Petroleum products comprise 69 percent of the energy required by DOD and 72 percent of the Navy's energy requirements (Figure 1-3). Furthermore, DOD and the Navy will continue to depend on liquid hydrocarbon fuels into the next century because of their need for mobile systems and because current ships and aircraft, which require such fuels, will remain in the inventory for many years. Even with active programs to improve the energy efficiency of mobile systems, the normal R&D cycle, from basic research to initial operational capability, is about 20 years. Thus, in 2000, the Navy estimates that it will need about 46.1 million bbl of liquid hydrocarbon fuel, comprising about 65 percent of its total energy requirements.[a]

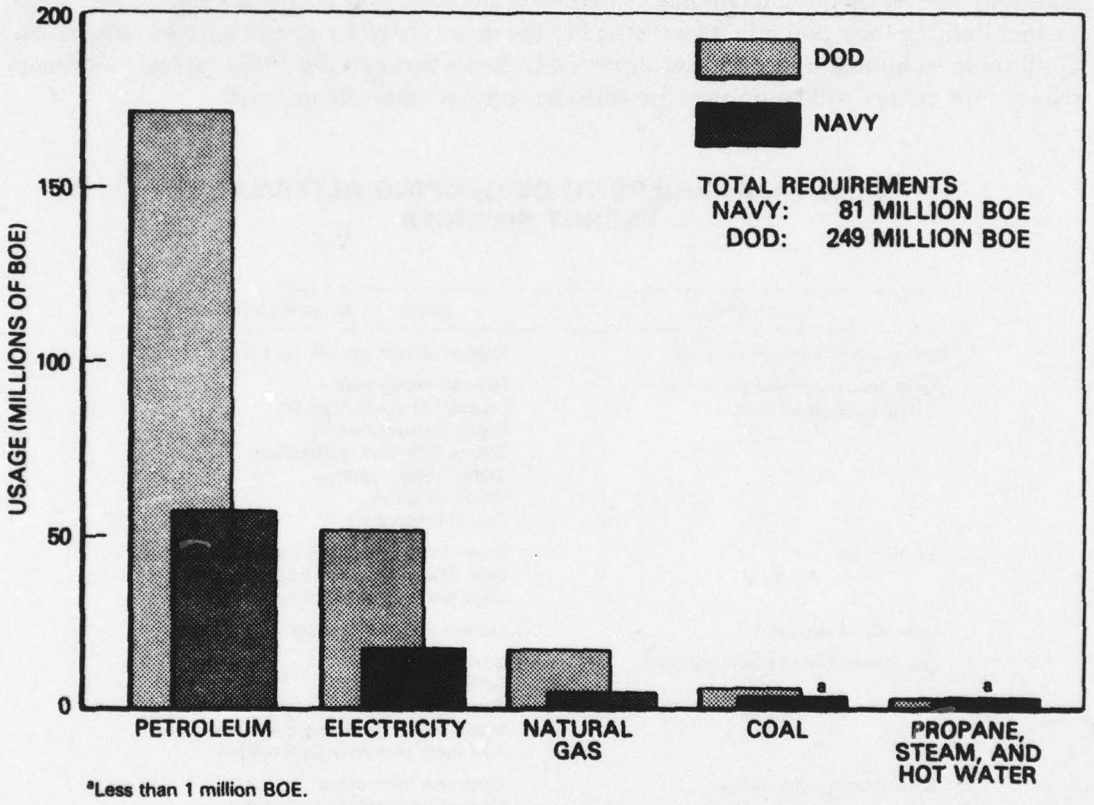


Figure 1-3. FY 1978 ENERGY USAGE (EXCLUDING NUCLEAR)

Satisfying Navy mission requirements for liquid hydrocarbon fuels is becoming increasingly costly as U.S. petroleum reserves dwindle. Further, continued heavy dependence on imported petroleum is risky, given the need to maintain national security and defense. Therefore, the Navy is preparing itself now for the time when world demand for petroleum exceeds supply. The Navy is adapting applicable energy technologies and technical pro-

cedures to reduce fuel consumption while maintaining the required readiness and operational effectiveness. The Navy's specific energy objectives are to:

- Achieve maximum practical energy conservation for facilities and operations, emphasizing conservation of petroleum and natural gas.
- Substitute, when economically practical, more abundant or renewable energy sources where petroleum or gas now are used.
- Consider the effect of energy policy and actions on the environment and on the health, welfare, and safety of personnel.

Current Navy quantitative energy goals are stated in the OPNAVINST 4100.5 series. Using FY 1975 as the baseline, this instruction sets percentages for reducing energy use in existing and new facilities, ground support equipment operation, fossil energy consumption per ship underway steaming hour and per flight hour, and fleet and shore fuel surveys, as well as saving energy through flight simulation, and by substitution of more abundant or renewable energy forms for petroleum or natural gas used in shore facilities.

The five key strategies selected to achieve the Navy objectives and goals are energy management planning, energy distribution and allocation, energy conservation, synthetic fuels, and energy self-sufficiency/alternative energy sources. The last three strategies, which require a large technology input, have become the basis for the Navy energy R&D program:

- Conservation—Provide technological solutions to achieve energy savings in all naval operations, principally by increasing the efficiency of energy use.
- Synthetic fuels—Provide technological solutions to enable Navy ships and aircraft to operate on fuels derived wholly or in part from domestic synthetic crudes (especially from oil shale) and on conventional petroleum fuels of relaxed or commercial specification.
- Energy self-sufficiency—Provide technological solutions to enable the economic use in Navy shore facilities of more abundant fossil fuels (such as coal) and renewable energy sources (such as solar, geothermal, and biomass) as substitutes for petroleum and natural gas.

The Department of the Navy's energy technology programs are organized and accomplished by means of the traditional ship, aircraft, and shore facilities platforms. Table 1-5 shows, by strategy and platform, the most significant Navy energy technology projects representing special military applications of energy technologies included in the supporting chapters of this *Energy Fact Book*. These projects are described briefly in the following paragraphs. (Detailed program descriptions are provided in the *Navy Energy R&D Program Plan, FY 1979-FY 1984.*)

Table 1-5. TECHNOLOGY PROJECTS BY STRATEGY AND PLATFORM

Strategy	Ships	Aircraft	Shore Facilities
Conservation Improved efficiency of naval operations	Ship drag reduction – Removal of biofouling – Prevention of biofouling – Hull coatings – Special application coatings – Noncoating protection – New hull design Improved propulsion system efficiency – Retrofit of steam-powered ships – Improved combustion controls – Improved fuel burner design – Improved standby main feed pump design – Economizer redesign – Machinery performance monitoring – Advanced ship propulsion systems More efficient auxiliary systems – Improved ship service electrical systems – Fresh water resource management – Improved pumping systems – More efficient lighting – Improved HVAC systems – Not underway steaming systems Ship energy analysis techniques – Ship energy use profiles – Ship total energy analysis – Fuel management analysis	Aircraft energy usage analysis – Procedures modification – Retrofit design changes to aircraft Adaptation of existing computer programs – Aircraft simulation program – Computer flight planning	Energy conserving building design – Energy conservation surveys of existing facilities – Thermal engineering of buildings – Low energy structures – Planning, engineering, and design of new facilities – Energy conservation investment program Electrical and lighting systems Heating, ventilating and air conditioning systems Energy monitoring and control systems Power generation and transmission Energy conserving use of vehicles – Vehicle operation – Vehicle procurement
Synthetic fuels Enable Navy to operate ships and aircraft on: – Fuels derived wholly or in part from domestically produced synthetic crudes – Conventional fuels of relaxed or commercial specification	Engine testing with synthetic fuel products Fuel properties Fuel flexibility Synthetic fuel toxicology	Engine testing with synthetic fuel products Fuel properties Fuel flexibility	Synthetic fuels for facilities – Liquid fuel flexibility in Navy shore boilers
Self-sufficiency Employ economically ashore more abundant and renewable energy sources as substitutes for petroleum and natural gas	Not applicable	Not applicable	Solar energy utilization – Heating and cooling – Electric systems – Desalination Coal utilization studies – Coal gasification – Fluidized bed boilers Geothermal energy experiments Wind energy experiments Energy from solid waste Energy storage and advanced power cycle studies

Ships—Energy Conservation

Ship Drag Reduction

The Navy has been investigating ways to reduce ship drag caused by the accumulation of fouling on ship hulls and appendages. Biofouling significantly increases drag as the ship moves through the water, and represents the single largest fuel consumption penalty identified to date. Specific cases have been observed where hull efficiency has been degraded by more than one-third after relatively short periods out of drydock. Underwater hull cleaning while ships are alongside piers is one means used by the Navy to reduce drag and conserve energy. Devices used are either diver-operated or semi-automatic brushing systems. Periodic hull cleaning between scheduled drydock periods may reduce average propulsion fuel consumption by 11 percent. Propeller cleaning, closely associated with hull cleaning, is accomplished by using brushes and polishing the propeller to make the surface smooth. Careful propeller cleaning can contribute as much as one-third of the total hull cleaning benefits, using significantly less than one-third of the total effort.

In addition to its programs to remove biofouling, the Navy has a program to develop methods for preventing biofouling on hulls and other ship surfaces. Elimination of fouling from ship's hulls may reduce propulsion fuel consumption by as much as 22 percent. This can be accomplished by applying improved hull and special application coatings, or ultrasonic prevention concepts. The Navy is experimenting with organometallic polymers that may eliminate biofouling for up to 5 years. This would make most hull cleaning unnecessary; however, these paints contain toxicants that kill the biofouling organisms, and must meet environmental and medical standards as part of the development process. These coatings also are not suitable for sonar fairings and propellers, but the Navy has special coatings under development that will resist the attachment of fouling to these surfaces while maintaining their structural integrity.

Sea chests of ships, while not underway, can become fouled much the same as hulls, but are not readily accessible for mechanical or water jet cleaning. Fouling causes inlet piping to become partially or totally clogged, which restricts or stops the flow of water into the ship when next underway. As a result, more power must be expended to obtain the water needed for condensers and heat exchangers. To prevent biofouling, the Navy is evaluating ultrasonic concepts..

In addition to removing or preventing biofouling from ship hulls and other surfaces, ship drag can be reduced by improved hull design. In the past, ship construction philosophy has focused on achieving maximum operational performance to the extent allowed by acquisition budgets; life-cycle (ship operating) costs have been a secondary consideration. Rising fuel costs now drive these operating costs upward to a point where they become a more predominant consideration in ship design.

Improved Propulsion System Efficiency

In an effort to improve the efficiency of ship propulsion systems, the Navy has initiated projects for retrofitting steam-powered ships and designing advanced propulsion systems. In

a retrofit project, the Navy is seeking to identify, document, and quantify the energy-intensive machinery systems and operational procedures for major ship classes, and to make modifications as feasible to save energy. As one approach, the Navy is modeling design heat balances for the FF-1052 class steam plant for comparison with heat balances for other ship classes. With the results, the Navy will be able to determine the need for potential fuel saving equipment and procedural modifications. Projects already identified are:

- Improved Combustion Controls. When Navy ships burned Navy standard fuel oil (NSFO), maximum combustion efficiency (proper fuel-air ratio) could be determined by observing the light brown ("economy") haze emitted from the smoke stack. Now that the Navy has converted to distillate fuels (DFM), there is no "economy" haze, and hence no visual gauge of combustion efficiency. To maintain boiler combustion at peak efficiency, the Navy is investigating the use of a combustion optimizer on all naval boilers to sample the combustion stack gases for optimum content of oxygen. This optimizer has the potential for saving in excess of 1 million bbl of fuel annually. The Navy is testing two commercial systems, using different sampling methods, to measure oxygen concentration in the stack gas.
- Improved Fuel Burner Design. The excess air levels required to burn boiler fuels effectively vary with boiler and burner design. If low excess air burners were used, excess air levels could be reduced 5 percent below present design values, resulting in an annual saving of as much as 350,000 bbl of fuel. The Navy is investigating the use of commercially available burners in Navy boilers, with particular emphasis on performance over a wide range of operations and demands.
- Economizer Redesign. When the Navy converted to distillate fuel, ship combustion plants were converted to handle the combustion properties of the new fuel. DFM generates more heat than did NSFO, which wastes fuel since the excess heat goes up the stack unused. The Navy is studying methods to modify existing economizers to capture more of the stack gas waste energy for use in raising the temperature of boiler feedwater. If successful, this modification could save 500,000 bbl of fuel annually.
- Improved Standby Main Feed Pump Design. In shipboard steam plants, main feed pumps supply the feedwater to boilers. A main feed pump failure is one of the most serious casualties that can occur, since insufficient makeup feedwater in boiler tubes can cause warping or bursting of the tubes, with a resultant loss of power. Because of the critical nature of this water supply, standby main feed pumps are kept idling constantly, requiring a considerable expenditure of energy (53,000 bbl/year for the FF-1052 class alone). The Navy is investigating the use of a standby main feed pump with the capability to accelerate from a cold start to rated capacity in sufficient time to protect boilers in the event of a casualty to one of the main feed pumps.
- Machinery Performance Monitoring. To enable shipboard engineering personnel to maintain the ship machinery plants at peak efficiency, the Navy is investigating a machinery performance monitoring system that will provide diagnostic information on plant conditions, such as pressures, vacua, temperatures, flow rates, heating values, shaft speed, electrical load, and stack oxygen. With these data, ship engineers can assess performance, and thus maximize opportunities for significant fuel savings.

Recent emphasis on simplicity and noise reduction has led to the use of gas turbine propulsion for new Navy combatant ships. However, these engines currently do not operate in an optimum fuel-efficient manner over the wide power range required of combatant ships. The Navy therefore is investigating less energy-intensive ship propulsion systems concepts. A leading candidate from the overall efficiency standpoint is the combined diesel or gas turbine propulsion plant, which uses a diesel for cruising power and then shifts to gas turbines for high speeds.

More Efficient Auxiliary Systems

The Navy has developed programs to improve the efficiency of ship auxiliary systems, including the ship's service electrical system; freshwater resource; pumping system; heating, ventilating, and air conditioning (HVAC) systems; lighting; and not underway steaming systems.

The ship's service electrical system is the second largest consumer of fuel on Navy ships. A program is under way to identify and develop alternative ship's service electrical system concepts that reduce energy consumption and life-cycle costs of equipment used. Major concerns in selecting generators are radiated noise characteristics; cost, weight, and volume penalty; and efficiency. Using the quiet diesel as the baseline, the Navy is evaluating quiet diesel and gas turbine-powered generating systems.

Potable (fresh) water used aboard ships regularly exceeds the 30 gal./man-day allowed by OPNAVINST 9330.5A by 10 to 20 gal./man-day. This excess occurs because much water is lost due to technical difficulties, the need for water is greater than original design values, and water management practices cannot cope with the complexity of the problem. To correct these problems, the Navy is seeking to identify freshwater flow patterns and formulate water resource management techniques to improve efficiency of freshwater production and use aboard ship. The goal is to reduce freshwater consumption to 20 to 25 gal./man-day. Specific areas being pursued include reduced-flow shower heads, recovery and reuse of laundry water, use of salt water in garbage grinders, recovery of unacceptable boiler feedwater, use of freshwater meters, and lower water pressures.

Shipboard pumping systems are large energy users and a potential source of energy savings. Work is under way to compile and analyze Navy, Coast Guard, and commercial design practices for pumping systems to determine how new or revised designs can save energy without sacrificing effectiveness.

HVAC systems, along with pumping and lighting systems, account for 60 percent of the fuel consumed for electric power generation aboard ships. Sources of alternative fuel-conserving HVAC equipment for the near-, mid-and far-terms have been identified, and 10 system concepts have been selected for further analysis.

Two alternative energy-conserving concepts for meeting shipboard lighting requirements have been identified. Analysis, test, and evaluation of 20 W fluorescent ballasts has begun, and studies of the utility of using high-intensity discharge lamps have been made. (It is uncertain that the latter will be acceptable for use aboard ship.)

Whenever ships are at anchor or dockside where no shore power is available, they must generate their own electrical power by keeping one of their boilers on line. The boiler operates at low efficiency since it is lightly loaded and a large portion of the auxiliary equipment is boiler related. The Navy is seeking to identify and develop energy-saving alternatives to steaming on a main boiler when not under way. For the FF-1052 class alone, it is estimated that over 120,000 bbl/year of fuel can be saved. The most promising prospect is the use of a diesel generator in conjunction with an auxiliary oil-fired boiler. System payback is estimated to be about 1 year.

Ship Energy Analysis Techniques

Recognizing the need for a readily accessible source of energy use data, the Navy Department developed the Navy energy usage profile analysis system (NEUPAS). Annual energy usage data is collected from ships, aircraft, and shore facilities, and is processed using source-dedicated computer programs that produce edited, reformatted files of energy data. The NEUPAS data base was incorporated into a "System 2000" data management system to increase data search and retrieval capabilities. Energy-usage projections derived yearly from the system are used to guide research projects and in planning the Navy energy program.

For diesel and gas turbine-propelled Navy ships, the propulsion, electrical, and auxiliary systems are designed independently to meet minimum performance standards. As a result, the overall plant efficiency can be quite low at part load, at which the ship operates most of the time. The Navy, through development of a total ship energy simulation model, is seeking to ensure incorporation of maximum utilization of all sources of energy into the ship design process. The model will be used to determine energy intensiveness of both proposed hardware developments and procedural modifications.

To further analyze energy usage, the Navy studied shipboard management of fuel to identify ways of reducing fuel loss. Based on a survey of 28 ships homeported in San Diego and Norfolk, the Navy concluded that up to 5.7 percent of the fuel consumed underway possibly could be lost overboard during fuel sampling, stripping, and reclamation processes. The Navy is seeking ways to recover fuel that might otherwise be lost when engaged in these activities.

Ships—Synthetic Fuels

To ensure that it is capable of fulfilling mission requirements, the Navy must have assured and secure supplies of fuels. Reduction of domestic petroleum production and reliance on imports has lead the Navy to pursue programs to develop a capability to utilize, in Navy systems, fuels derived from a wider variety of crude stocks, including synthetics. (Synthetic fuels, whether derived from coal, oil shale, tar sands, or biomass, are discussed in detail in subsequent technology chapters.)

Engine Testing with Synthetic Fuel Products

The suitability of alternative fuels for use in naval boilers, diesel engines, and gas turbines is to be determined through tests in small-scale combustors, full-scale engines, and fuel

system components, as well as in sea trials. The Navy began investigating the feasibility of using synthetic fuels in military equipment in 1974 when synthetic crude derived from coal at the Char-Oil Energy Development pilot plant was provided to the Navy by the Department of the Interior for testing as a ship fuel. Sea trials, conducted on the U.S.S. Johnston using fuel produced from this crude, demonstrated the potential of using synthetic fuels for Navy applications.

In 1974, the Navy served as the lead agency for a joint DOD, National Aeronautics and Space Administration (NASA), Coast Guard, Maritime Administration (MARAD), and Energy Research and Development Administration (ERDA) project to refine and test fuels derived from 10,000 bbl of crude shale oil. The fuel types produced were gasoline, JP-4, JP-5/Jet A, DFM/DF-2, and heavy fuel oil. These fuels were tested at various government and industry laboratories.

Navy test and evaluation efforts included:

- Tests of DFM in a single-burner boiler, a three-cylinder diesel, and an NTCC-350 six-cylinder diesel engine. Its performance compared favorably with that of standard DFM.
- Gas turbine tests using DFM, conducted by Detroit Diesel Allison, Pratt and Whitney, and General Electric.

The 10,000 bbl shale oil project culminated in the successful operational flight of a T-39 jet aircraft by the Air Force; the successful operational cruise of the Great Lakes steamer, Edward B. Green, sponsored by the Navy, MARAD, and Coast Guard; and the operational testing of a jeep (L-141) engine by the Army. These tests clearly demonstrated the feasibility of using crude shale oil as a feedstock for military fuels, particularly those in the middle-distillate range (jet and diesel fuels).

As a follow-on to the 10,000 bbl shale oil refining and testing project, the Navy is serving as the contracting agency and project director for a joint DOD-NASA-Department of Energy (DOE) program, which began in 1976, to acquire, refine, and test fuels derived from shale oil produced by the Paraho process on the Naval Oil Shale Reserve near Rifle, Colorado. From January 1977 through September 1978, 88,225 bbl of crude shale oil were produced under Navy and DOE contracts in support of this program. Between October 1978 and February 1979, the shale crude was refined into military specification fuels for testing by the military services and other agencies.

A computerized file of reports relating fuel properties and engine performance was developed and a methodology for extracting and filing engine test data formulated. Sources of additional fuel performance data were located within other government agencies and some engine manufacturers.

Fuel Properties

Synthetic fuel crude samples, acquired from various pilot demonstration and commercial sources, are screened through the tests required by the appropriate military specification, for example, JP-5 and DFM. On the basis of these screening tests, candidate fuels are

characterized by physical and chemical properties. Crude assay analyses of various synthetic crudes are conducted to determine the potential yield and quality of military specification fuels. These analyses are conducted in cooperation with DOE and other DOD laboratories. In addition to operational fuel considerations, these assay analyses will further identify potential sources of other synthetic products (such as lubricants and hydraulic fluids) of interest to the Navy.

Crude assays have been performed on samples of shale oil crude from seven sources and six coal-derived liquids. Refined fuels have been analyzed to determine their compliance with or deviation from requirements. Fuels studied included those derived from oil shale, tar sands, and coal, and particularly the DFM and JP-5 products from the 10,000 bbl shale oil experiment. In addition, type analyses, upgrading studies, and wear and comparability evaluations were conducted on some fuels. Physical and chemical property determinations were started on samples of each of the refined products from the recent production of Paraho shale crude.

Fuel Flexibility

The Navy's ability to maintain full operational readiness is to be ensured by having available sufficient alternative fuel sources during circumstances of reduced availability or embargo of the principal military specification fuel supplies. In addition, criteria for evaluating the effects of alternative fuels, conventional and synthetic, on system performance, safety, reliability, maintainability, and logistics are to be established, and information is to be generated for planning future engines and fuels-handling equipment with fewer constraints on fuel properties. Work statements have been prepared to procure contractual services to develop alternative fuels evaluation procedures for Navy ship engine systems.

Synthetic Fuel Toxicology

Shipboard atmospheric sampling has been conducted to determine the concentration and characteristics of hydrocarbon vapors in the working spaces aboard ships. The data will be used to estimate the concentrations to be expected during the use of synthetic fuels. Candidate synthetic liquid fuels are being examined by the U.S. Naval Medical R&D Command for possible toxic effects. The results of this work, when combined with vapor concentration estimates, will be used to determine potential health effects and recommend any procedures or precautions that might be needed when operating with synthetic fuels.

Aircraft—Energy Conservation

Aircraft Energy Usage Analysis

The two major objectives of the aircraft energy usage analysis program are to identify current energy-saving technologies that can be applied efficiently to Navy aircraft by 1985, and to identify changes to current aircraft operations, tactics, and payloads that can save energy without degrading mission effectiveness. The two principal users of aviation fuel are the F-4 (19.4 percent) and the P-3 (16.3 percent). These two aircraft fleets have been selected for the first technology studies to ascertain methods of conserving fuel through operational procedures and simple design retrofits.

Two examples of operational procedures modifications illustrate the types of initiatives being investigated. Procedures modifications for patrol aircraft include taxiing on two-inboard engines, flying at NATOPS recommended altitude and at maximum range airspeeds, loitering with two or three engines unless restricted by mission environment or safety of flight, minimizing overfueling, and using Lockheed's JETPLAN for optimum flight profiling.

In its work on design retrofits to make aircraft more fuel conserving, the Navy is investigating the effects of simple design modifications on aircraft dimensions and weight; fuel usage during significant flight conditions; aerodynamics, stability and control, handling qualities, and performance during flight; survivability, vulnerability, maintainability, and reliability; facilities, manpower, and supply networks; development and modification costs; and initial operating capability for aircraft.

Adaptation of Existing Computer Programs

Since 1975, the Navy increasingly has emphasized training in a simulated environment in conjunction with training in an operational environment. Types of simulators include weapons systems trainers, night carrier landing trainers, flight instrument trainers, air combat maneuvering simulators, and initial F-18 training devices. In FY 1977, training simulators and devices replaced about 145,000 flying hours, thus saving about 75 million gal. of fuel.

The Navy also uses a computerized flight planning service to optimize routing, altitude, airspeed, cruise management, fuel load, and payload trade-offs for point-to-point flights. Lockheed's JETPLAN was used to plan about 7,500 P-3 flights in FY 1976, with a savings of about 33,000 bbl of fuel. (JETPLAN is available only for the P-3 at this time.)

Aircraft—Synthetic Fuels

To ensure that it is capable of fulfilling mission requirements, the Navy must have assured and secure supplies of fuels. Reduction of domestic petroleum production and reliance on imports has lead the Navy to pursue programs to develop a capability to utilize, in Navy systems, fuels derived from a wider variety of crude stocks, including synthetics. (Synthetic fuels, whether derived from coal, oil shale, tar sands, or biomass, are discussed in detail in subsequent technology chapters.)

Engine Testing with Synthetic Fuel Products

The suitability of alternative fuels for use in Navy aircraft engine systems is to be determined through tests in small-scale combustors, full-scale engines, and fuel system components, as well as in sea trials. In 1974, the Navy served as the lead agency for a joint DOD, NASA, Coast Guard, MARAD, and ERDA project to refine and test fuels derived from 10,000 bbl of crude shale oil. The fuel types produced were gasoline, JP-4, JP-5/Jet A, DFM/DF-2, and heavy fuel oil. These fuels were tested at various government and industry laboratories.

Navy test and evaluation efforts included a TF34 30.9 hour engine test using JP-5 derived from shale oil. Engine performance at sea-level conditions and altitude starting were equivalent to the performance of petroleum-derived JP-5.

The 10,000 bbl shale oil project culminated in the successful operational flight of a T-39 jet aircraft by the Air Force; the successful operational cruise of the Great Lakes steamer, Edward B. Green, sponsored by the Navy, MARAD, and Coast Guard; and the operational testing of a jeep (L-141) engine by the Army. These tests clearly demonstrated the feasibility of using crude shale oil as a feedstock for military fuels, particularly those in the middle-distillate range (jet and diesel fuels).

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Experimental combustor tests have been completed on JP-5 derived from tar sands, oil shale, coal, and petroleum in which chemical and physical properties were controlled to deviate from JP-5 specification limits in specific ways. Flame radiation (which affects durability) and smoke varied as a function of hydrogen/carbon ratio for all fuels, except that coal derived fuel was slightly higher in these properties than would be expected from the trend of the other fuels.

The use of synthetic aviation fuels also will be evaluated in a seagoing environment to detect problems that might arise in routine operations. Additionally, the evaluation will permit isolation of any unusual performance characteristics resulting from the exposure of the synthetic fuel to practices currently employed at sea for storing and decontaminating fuel.

Fuel Properties

Synthetic fuel crude samples, acquired from various pilot demonstration and commercial sources, are screened through the tests required by the appropriate military specification, for example, JP-5 and DFM. On the basis of these screening tests, candidate fuels are characterized by physical and chemical properties.

Crude assays have been performed on samples of shale oil crude from seven sources and six coal-derived liquids. Refined fuels have been analyzed to determine their compliance with or deviation from military specification requirements. Fuels studied included those derived from oil shale, tar sands, and coal, and particularly the DFM and JP-5 products from the 10,000 bbl shale oil experiment. In addition, type analyses, upgrading studies, and wear and comparability evaluations were conducted on some fuels. Physical and chemical property determinations were started on samples of each of the refined products from the recent production of Paraho shale crude.

A study of the basic nitrogen compounds in shale oil JP-5 has continued. These data are being used in support of the joint DOD-DOE-NASA shale oil refining program, indicating the severity of the refining required to achieve an acceptable nitrogen level. Thermal stability studies are also being conducted with a single tube of an aircraft heat exchanger to establish the losses in heat exchanger effectiveness resulting from deposit levels produced by fuels of varying thermal oxidation stability. These data will be used to assess stringency of the current level of thermal stability as required by the JP-5 specification.

Fuel Flexibility

The Navy's ability to maintain full operational readiness is to be ensured by having available sufficient alternative fuel sources during circumstances of reduced availability or embargo of the principal military specification fuel supplies. In addition, criteria for evaluating the effects of alternative fuels, conventional and synthetic, on system performance, safety, reliability, maintainability, and logistics are to be established, and information is to be generated for planning future engines and fuels-handling equipment with fewer constraints on fuel properties. Work statements have been prepared to procure contractual services to develop alternative fuels evaluation procedures for Navy aircraft engine systems.

A study of the effects of the use of emergency fuels on aircraft performance was conducted with the blending of 10 percent and 20 percent of two different batches of DFM with JP-5 fuel. Evaluation of the physical properties showed that these blends had acceptable viscosity. The freezing point and thermal oxidation stability, however, were unacceptable by a large margin. Fuel control and coalescer tests will be run on neat DFM (the worst case). A T63 engine performance/exhaust emission test will be conducted with a 20 percent DFM blend. A contract to evaluate the combustion properties of broad specification JP-5, and blends of DFM with JP-5 and gasoline using a T63 combustor has been awarded. The fuel/air ratios for ignition and blowout, flame radiation, exhaust smoke, and combustor performance for these fuels are being measured to determine the conditions under which such blends could be used when military specification fuels are unavailable or in short supply.

Shore Facilities—Energy Conservation

Energy Conserving Building Design

As a first step after the 1973 oil embargo, the Navy started energy conservation surveys of all naval activities. The objectives of these surveys, for which R&D funds have been applied, were to identify and document wasteful energy practices and to help develop individual energy conservation and contingency plans. Another important objective was to provide technical assistance to activities in developing self-amortizing repair and retrofit projects that could be supported within existing budgets. Both of these activities continue, emphasizing more complex and technically sophisticated projects. Furthermore, all energy features of each major project are thoroughly analyzed, including computer simulation of various system alternatives. Design engineers are able to incorporate energy-savings features into all major new construction and rehabilitation projects.

Through the energy conservation surveys, thermal energy losses were discovered in

Navy buildings. Infrared imagery has been effective in pinpointing areas of thermal loss, and projects are under way to improve, replace, or patch existing wall insulating materials and use polyurethane coatings for coating metal roofs. Several different commercially available products are being investigated.

Another R&D project calls for investigating the use of low energy structure technology in buildings. The objective is to examine future Navy building requirements and the emerging technologies available from DOE and the private sector, and determine whether an experimental Navy adaption program is necessary.

Electrical and Lighting Systems

The Navy is interested in applying the latest technology to conserving energy in electrical systems of all types, including lighting, motors, and distribution systems. Lighting alone uses 30 percent of all electric power. Areas being investigated are sizing of electrical feeders based on life-cycle costs rather than minimum code regulations, advanced illumination technology, energy loss in distribution systems, and use of computerized control systems.

Heating, Ventilating, and Air Conditioning Systems

Since more efficient HVAC systems have the potential for saving significant amounts of energy, the Navy is investigating systems with improved part-load performance, the merit of heat pumps, and the use of seawater air conditioning systems as candidates for effecting these savings.

Energy Monitoring and Control Systems

The Navy has determined that energy monitoring and control systems (EMCSs) offer potential energy savings of 10 to 40 percent, and is developing procedures for identifying and applying optimum EMCSs for each Navy shore activity. Efforts are under way at two Navy hospitals to develop guidance and retrofit techniques for existing older generation EMCSs with modern microprocessing techniques and hardware. Follow-on studies of manpower reallocation, energy budgeting, local control improvements (thermostats, "dead band" controls, and microprocessor time clocks), and advanced EMCS concepts (such as distributed processing) at hospitals, housing areas, and public works centers are in progress. The Navy is concentrating a significant part of its effort on procuring and testing hardware and software for automated single-building controllers.

Power Generation and Transmission

Early studies have shown that more than 20 naval bases in the continental United States are suitable for cogeneration installations. Of these, the Naval Air Station at Jacksonville, Florida, has been selected for a cogeneration model study. In addition, a joint DOE-Navy program to conduct a 3-year demonstration of the new organic Rankine cycle bottoming technology will be performed at the diesel-electric power plant, Naval Air Station, Bermuda. Cogeneration—that is, the simultaneous production of electrical or mechanical energy and useful thermal energy—is discussed in Chapter 17.

The Navy is also studying methods for preventing energy loss and rapid deterioration of steam piping systems as a result of water intrusion into the air space of underground pressurized steam lines. The Navy is testing both infrared detectors and sulfur hexafluoride leak detectors for use in detecting leaks and measuring energy loss.

Energy Conserving Use of Vehicles

To conserve fuel and reduce operating costs, the Navy initiated a program in FY 1975 to increase the number of compact and intermediate sedans and administrative vehicles. All naval personnel are being made aware of the need to operate vehicles in an energy-conserving manner through the Navy Department energy awareness program. This program encourages private vehicle carpooling, which is included in the evaluation checklist for the annual Secretary of the Navy Energy Conservation Awards Program. In addition, the awareness program facilitates the distribution of literature to all commands and activities on energy-efficient vehicle operation.

Shore Facilities—Synthetic Fuels

The capability of Navy boilers is to be expanded to allow firing of a wider range of fuel oils. Test programs are being conducted in Navy shore boilers with mixtures of waste fuels and fresh fuel oils. The objective of this work is to develop guidelines for the safe and economical use of waste oil at Navy shore facilities.

Firing tests were conducted using blends of up to 100 percent contaminated distillate fuels in heavy (No. 5) fuel oil, blends of up to 50 percent used lubricating oils in light (No. 2) fuel oil, straight used lubricating oils with 0.4 percent and 4.4 percent suspended water, and contaminated diesel fuel. Test results generally show that waste oil blends can be fired satisfactorily in boilers without appreciable difference from regular fuel oil firing. Minor adjustments are sometimes required to compensate for effects resulting from possible viscosity variations.

Synthetic fuels and blends with fossil fuels will be tested systematically to determine fuel properties; fuel handling, preparation, and safety techniques; necessary modifications to boiler and fuel supply systems; multifuel capability; long-term operating and maintenance requirements; pollutant emissions related to boiler operations; and operating procedures for maximum boiler efficiency.

Shore Facilities—Energy Self-Sufficiency

Solar Energy Utilization

The Department of the Navy is monitoring DOE's solar heating and cooling programs to incorporate the technology into the Navy system. (Solar energy technology is discussed in detail in Chapter 10.) The Advanced Energy Utilization Test Bed (AEUTB), constructed at the Navy's Civil Engineering Laboratory as part of the Thermal Engineering of Buildings technology goal, will be used for testing full-scale solar collectors, storage techniques, solar stills, heat pumps, and other HVAC systems. System performance will be analyzed and characterized for the local climatic conditions at Navy facilities.

The Navy is investigating direct solar-to-electric conversion systems for providing power for Navy bases or activities, isolated loads, and mobile forces. Power for isolated loads (ranging from a few watts to nearly 100 kW) requiring on-site generators is of particular interest to the Navy because supplying fuel for the generators is often costly and difficult. Photovoltaic cells, although costly initially, are a possible option because ongoing support requirements are low.

Desalination plants, which generally use oil or other fuels, currently are operating in many naval facilities around the world. Application of solar powered stills, as developed by the national program, could replace the need for a large proportion of the oil or other fuels used in desalination. Application of this technology is feasible because an abundance of sea water and sunshine often exists together, a condition ideally suited for producing fresh or distilled water with solar powered stills.

Coal Utilization Studies

All of the military departments have been requested to burn coal in increasing quantities to reduce dependence on petroleum fuels. However, coal is not clean burning and its use often will be at variance with environmental quality standards. Furthermore, both fuel and ash handling require additional equipment and manpower. The use of a clean liquid or gaseous fuel derived from coal would permit the continued use of presently installed oil- and gas-fired boilers, as well as installed steam distribution systems. Techniques for liquefying and gasifying coal are being developed as part of the national energy program (see Chapter 4). In the future, coal gasification and other synthetic fuels may permit the use of combined cycles where gas turbines generate electricity and their exhaust heat fires boilers for steam generation (see Chapter 17).

The use of fluidized-bed boilers is another technology alternative to conventional burning of coal. This type of boiler is inherently smaller and less capital intensive than pulverized coal units and may present some pollution control advantages. The Navy is supporting DOE's fluidized-bed boiler demonstration at the Great Lakes Naval Training Center. Details about fluidized-bed boiler technology are included in Chapter 4.

Geothermal Energy Experiments

A number of Navy bases, both in the continental United States and at various locations throughout the world, are situated on or near geothermal energy resources. At remote sites, such as the naval facilities at Adak and Guam, fossil fuels must be imported at great expense to generate electricity and to heat living and working quarters. Where available, geothermal energy can provide these needs at substantial savings. For instance, about 4.1 million gal. of JP-5 jet fuel is used each year at Adak to generate electrical power, and another 3.1 million gal. is used to heat facilities. Use of geothermal energy at Adak, if the resource is proven, could result in significant yearly savings. This area has been selected for further resource evaluation. The Coso Thermal Area located on and adjacent to the Naval Weapons Center in the Mojave Desert of California is one of a limited number of sites within the continental United States with commercial grade electric power generation potential and a significant test and development program (see Chapter 9).

Wind Energy Experiments

The application of wind power at naval installations offers a pollution-free, inexhaustible source of energy. Developments in the national program (Chapter 11) are being followed to adapt them to Navy needs and to develop methodologies for Navy implementation. Small wind turbine generators integrated with electrical grids are being evaluated; one is a 6 kW variable-speed wind turbine generator with a single-phase synchronous inverter at the AEUTB, and the other is a 20 kW variable speed turbine with a three-phase synchronous inverter at the Marine Corps Air Station, Kaneohe Bay, Hawaii.

Energy from Solid Waste

The Resource Recovery Act of 1976 directs the use of recovered material-derived fuel to the maximum extent practicable in federally owned fossil fuel fired energy systems that have such technical capability. In compliance with this Act, the Navy is operating two 40 ton/day packaged heat-recovery incinerators, one at Naval Air Station, Jacksonville, Florida, and the other at Naval Station, Mayport, Florida. These incinerators are providing data to determine the conditions, particularly minimum capacity, under which either type of heat-recovery incinerator would be cost-effective and sufficiently reliable elsewhere in the naval shore establishment. Energy from solid waste technology is discussed in Chapter 12.

Energy Storage and Advanced Power Cycle Studies

The Navy has a continuing need for energy self-sufficiency at its bases, and recent advances in thermal energy storage technology enhance the feasibility of adapting alternative energy systems to naval applications. The state of the art in advanced power cycles (fuel cells, Stirling, high-temperature Brayton or Rankine) also is being monitored for potential applications and ultimate demonstration at naval facilities. Engines and burners using these cycles can operate on locally synthesized fuels (hydrogen, ammonia, and methanol) and thus aid naval self-sufficiency.

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8. U.S. Department of the Navy, "Energy Plan and Program 1978," OPNAV 41P4, 1978.

2. PETROLEUM

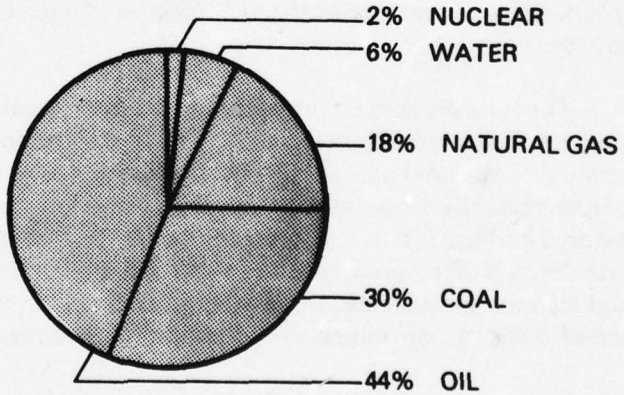
Petroleum and petroleum products contributed about 44 percent to worldwide demand for energy in 1977, nearly as much as natural gas and coal combined (Figure 2-1). In the United States, crude oil and other petroleum liquids account for almost one-half of total U.S. energy consumption (Table 2-1) with almost one-half of this amount derived from foreign imports of petroleum liquids and refined petroleum products.[1] Use of petroleum in the U.S. economy is illustrated in Figure 2-2.

Table 2-1. PETROLEUM FACTS

Energy content	5.8 million Btu/bbl
Proved U.S. reserves, 1977	29.5 billion bbl (including 10 billion bbl in Alaska)
U.S. resources	100 billion to 180 billion bbl of crude oil as potential remaining resources
U.S. production, 1977	3.6 billion bbl/year (including 2.99 billion bbl/year of crude oil)
Imports, 1977	3.2 billion bbl/year (49 percent of consumption)
U.S. consumption, 1977	6.5 billion bbl/year
Contribution to demand	Petroleum supplied 46.8 percent of the 1977 U.S. energy demand

Sources: National Petroleum Council, "Domestic Oil and Gas Availability," *U.S. Energy Outlook,* December 1972; *International Petroleum Encyclopedia* (Tulsa, OK: Petroleum Publishing Company, 1978); U.S. Geological Survey, "Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States," Circular 725, 1975; and British Petroleum, "BP Statistical Review of the World Oil Industry," 1977.

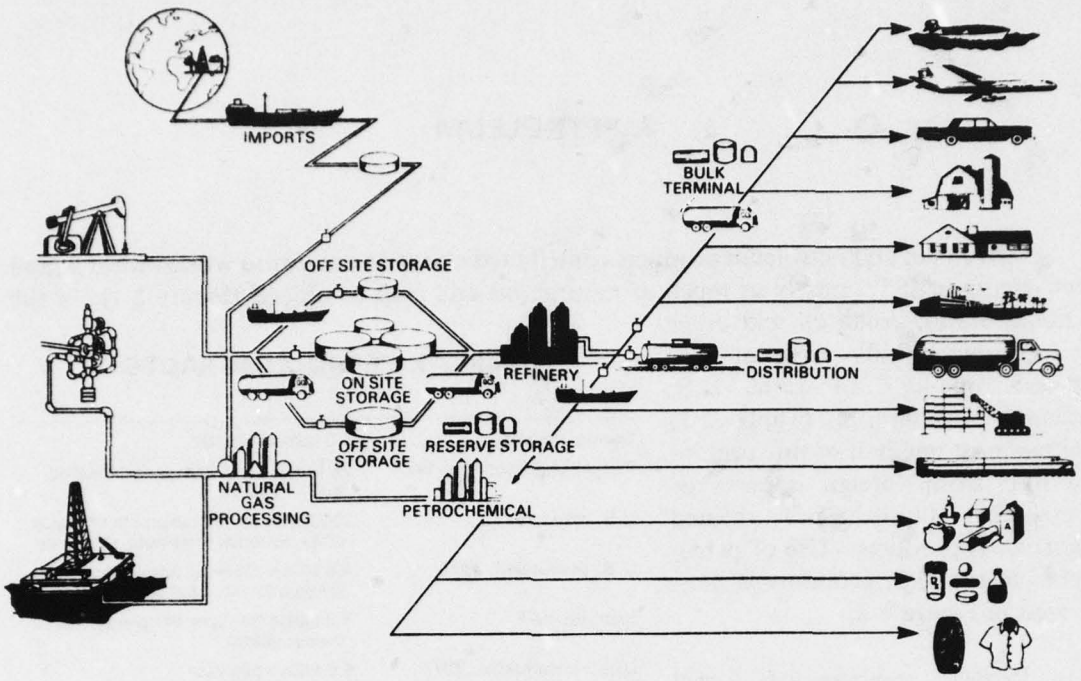
Proved reserves of world crude oil total an estimated 646 billion bbl, as shown in Table 2-2. Proved petroleum reserves are those quantities of crude oil known to be underground that can be produced under prevailing economic and technical conditions. Of these reserves, less than 5 percent (29.5 billion bbl) is located in the United States,[2] and approximately 66 percent (425.5 billion bbl) is located in the Middle East and Africa. Mexico's proved petroleum reserves at the end of 1977 were estimated at 14 billion bbl. In 1978, Mexico reported oil and gas finds that could make it one of the world's major producers, with the greatest of all petroleum reserves. A new find of more than 100 billion bbl of oil and 40 trillion cubic feet (tcf) of gas could bring the total resource to more than 300 billion bbl of oil equivalent.



Source: British Petroleum, "BP Statistical Review of the World Oil Industry," 1977.

Figure 2-1. 1977 DISTRIBUTION OF WORLD ENERGY SOURCES

The North Sea field, devel-



Source: U.S. Bureau of Mines, "Petroleum," Bulletin 667, 1975.

Figure 2-2. PETROLEUM INDUSTRY FLOW IN THE U.S. ECONOMY

oped in 1968, contains 10 billion to 40 billion bbl of oil and 26 tcf of natural gas. Estimated proved recoverable reserves in the Prudhoe Bay field, discovered in 1968 on Alaska's North Slope, amount to 9.6 billion bbl of crude oil and 26 tcf of natural gas. Surveys suggest that sedimentary formations in the U.S. Atlantic Outer Continental Shelf may contain oil and gas reservoirs.

The total amount of original oil-in-place (resource) in the United States is estimated by the U.S. Geological Survey (USGS) to be 200 billion to 300 billion bbl.[3] The petroleum resource is the total amount of oil in the earth's crust in such form that its economic extraction is currently or potentially feasible. Some portion of the resource may remain undiscovered because it is in reservoirs too remote, too small, or too hidden by geologic complexities. Even if discovered, much of this resource cannot be produced under current economic and technological conditions. Differences in resource and reserve estimates result from the use of different techniques in estimation procedures.

PETROLEUM AVAILABILITY AND UTILIZATION

Production and Consumption

Table 2-3 shows the major oil producers and consumers. The United States alone uses

Table 2-2. DISTRIBUTION OF WORLD PROVED OIL RESERVES, 1 JANUARY 1978

Area/Country	Proved Oil Reserves	
	Billion Barrels	Percent of Total
Middle East		
Saudi Arabia	150.0	23.2
Iran	62.0	9.6
Kuwait	67.0	10.4
Iraq	34.5	5.3
Abu Dhabi	31.0	4.8
Other	21.7	3.4
Communist countries		
USSR	75.0	11.6
China	20.0	3.1
Other	3.0	0.5
Africa		
Libya	25.0	3.9
Nigeria	18.7	2.9
Other	15.6	2.4
North America		
United States	29.5	4.6
Canada	6.0	0.9
Mexico	14.0	2.2
Europe	26.9	4.2
South America and Caribbean	26.4	4.1
Asia-Pacific	19.7	3.1
World total	645.9	100.0

Source: *International Petroleum Encyclopedia* (Tulsa, OK: Petroleum Publishing Company, 1978).

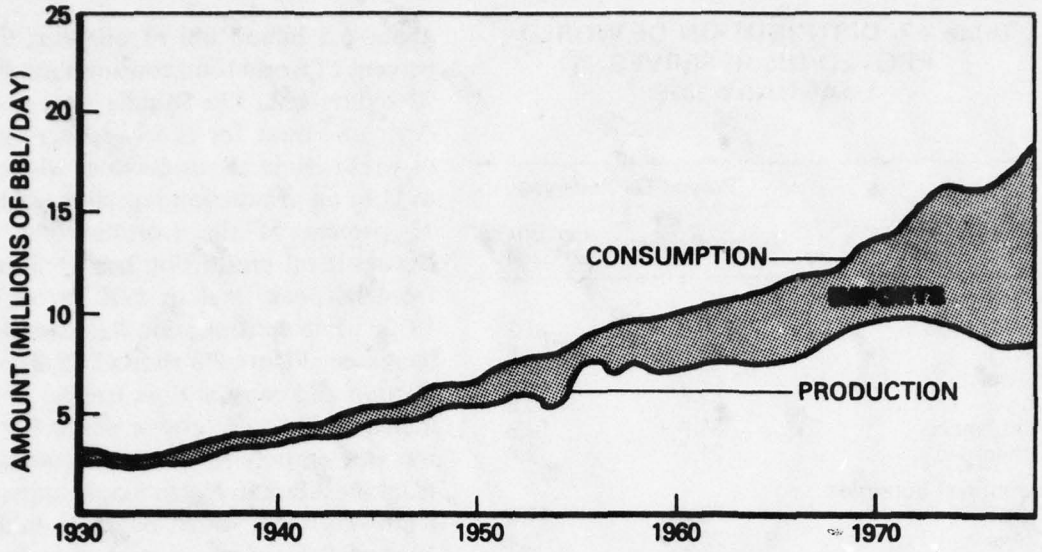
about 6.5 billion bbl of oil/year, 29 percent of world total consumption of 22 billion bbl. The Middle East and Africa account for nearly 50 percent of world crude oil production, whereas U.S. oil production represents only 13 percent of the world's total.[1,2] Domestic oil production has declined from its peak level in 1970 through 1972, while consumption has steadily increased. Figure 2-3 shows U.S. production and consumption trends. The increased U.S. oil production in 1977 was due entirely to the crude coming from the Alaskan North Slope; output from this field, which began in mid-1977, did not reach its current capacity of 1.2 million bbl/day until early 1978.[4]

As shown in Table 2-1, U.S. imports of petroleum and petroleum products accounted for 49 percent of its petroleum consumption in 1977.[1] The American Petroleum Institute (API) reported that about 84 percent of these imports were from the Organization of Petroleum Exporting Countries (OPEC), indicating another OPEC oil embargo would have serious implications for the United States.[2]

Table 2-3. MAJOR CRUDE OIL PRODUCERS AND CONSUMERS, 1977

Area	Production (Millions of bbl/day)	Percent of Total Production	Consumption (Millions of bbl/day)	Percent of Total Consumption
Middle East	22.35	36	1.57	3
Communist countries	13.08	21	11.55	19
North America	11.44	18	19.74	32
Africa	6.29	10	1.17	2
Latin America	4.71	8	3.99	7
Asia	2.41	4	2.59	4
Western Europe	1.43	2	14.24	23
Japan	.01	Negligible	5.35	9
Other countries	.45	1	.80	1
World total	62.16	100	60.98	100

Source: British Petroleum, "BP Statistical Review of the World Oil Industry," 1977.



Sources: DeGolyer and MacNaughton, "Twentieth Century Petroleum Statistics," (Dallas, TX: 1978); and *International Petroleum Encyclopedia* (Tulsa, OK: Petroleum Publishing Company, 1978).

Figure 2-3. U.S. OIL PRODUCTION AND CONSUMPTION

To forestall the impact of an oil embargo, the United States is stockpiling an emergency supply of crude oil under the Strategic Petroleum Reserve (SPR) program. The storage sites for the first phase of the program are four salt domes and mines along the Gulf Coast. Crude oil began flowing to the strategic storage sites in the summer of 1977, climaxing more than 1½ years of planning and development. Currently, the 70 million bbl in storage are at three sites: Bayou Choctaw and West Hackberry, both in Louisiana, and Bryan Mound in Texas. The target total for the three sites is 147 million bbl. An additional 75 million bbl will be stored at the Weeks Island, Louisiana, storage site, which is expected to begin operation in 1979. The long-range plan calls for 500 million to 1,000 million bbl of imported crude to be stored by the end of 1980.[2] The Department of Energy (DOE) is to have 250 million bbl of crude stored by early 1980. In 1979, imports for the oil storage program will become significant because they are expected to average more than 300,000 bbl of crude/day.[2]

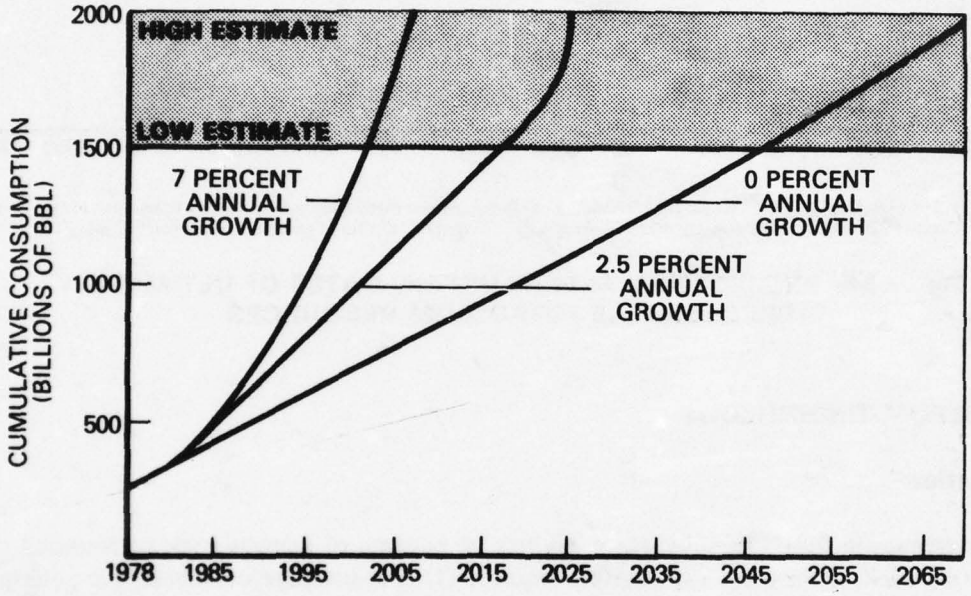
Exhaustion

On the basis of physical production capacity at what M. King Hubbert (formerly of USGS) calls "an orderly undisturbed evolution of the petroleum industry," world oil production would peak in the mid-1990s at a rate of 37 billion bbl of oil/year.[5] This production depends on economic and technical feasibility of extracting oil, methods used to estimate reserves, and the degree of certainty assigned to the estimates.

Theoretical world oil exhaustion dates are calculated for the resource boundaries as a proxy for depletion dates. The ultimate depletion date is when the amount of available resource falls below that required to maintain current consumption patterns. Specifically,

depletion dates (or transition periods) are determined by world oil production, consumption, and pricing policies, and by ultimately discovered recoverable oil. The exhaustion date is the date that cumulative consumption of oil exceeds total ultimately recoverable resources. The calculation assumes that sufficient oil is produced and available to meet the demand. In actual practice, production will decline as the reserves are used, thereby delaying the actual exhaustion date by creating a supply shortfall (that is, depletion). Calculating theoretical exhaustion dates indicates the length of time current production and consumption trends could continue until oil supplies are exhausted.

Three alternative oil consumption growth rates are used to project world exhaustion dates (see Figure 2-4). If the conservative 2.5 percent annual consumption growth rate is assumed, the entire estimated range of recoverable resources would be exhausted between 2017 and 2025. Using the historical growth rate of 7 percent, exhaustion would occur sometime between 2003 and 2007. In the unrealistic and optimistic case of no increase in consumption, exhaustion would occur by 2070.

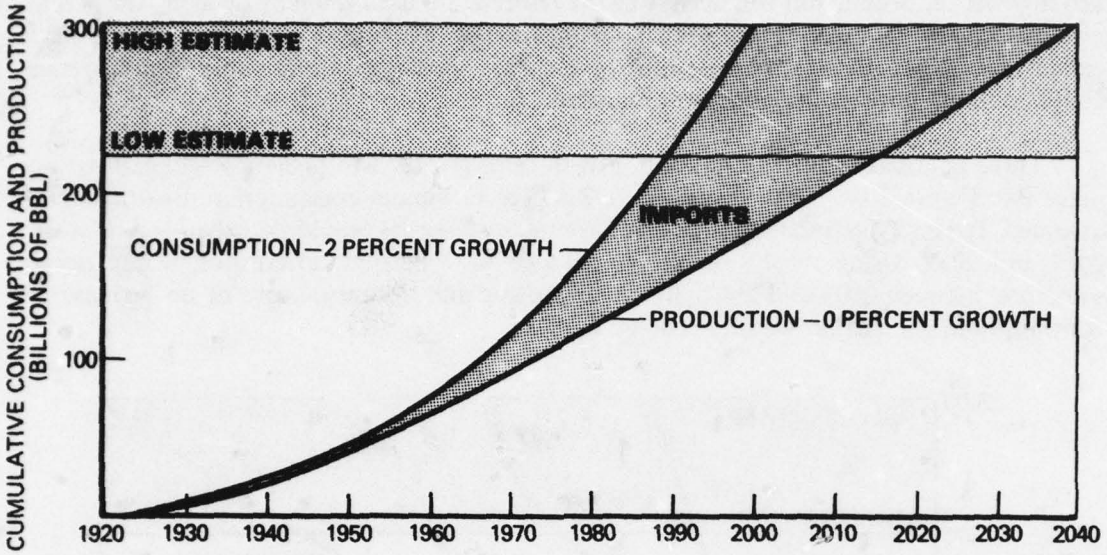


Sources: John D. Moody and Robert Geiger, "Petroleum Resources: How Much Oil and Where?" *Technology Review*, March-April 1975; Organization for Economic Cooperation and Development, "Energy Prospects to 1985," 1975; Congressional Research Service, "Project Interdependence: U.S. and World Energy Outlook Through 1990," No. 95-31, June 1977; and National Academy of Sciences, "Mineral Resources and the Environment," February 1975.

Figure 2-4. PROJECTED WORLD EXHAUSTION DATES OF ULTIMATELY RECOVERABLE PETROLEUM RESOURCES

Theoretical exhaustion dates for specific world areas will vary significantly because of the distribution of oil-bearing formations, local production and consumption patterns, and different trade policies. The United States faces greater dependence on oil imports as its oil resources are depleted. On the basis of projected no-growth production rates (excluding imports), current U.S. oil resources could be exhausted between 2012 and 2039 (Figure 2-5).

On the other hand, the Soviet Union has at least 20 more years of available oil than the United States. In choosing an alternative, many countries will still depend on foreign oil to extend available domestic oil resources. Since western Europe relies heavily on foreign sources, its estimated resource exhaustion date can be postponed to about 2032.



Sources: U.S. Geological Survey, "Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States," Circular 725, 1975; and DeGolyer and MacNaughton, "Twentieth Century Petroleum Statistics" (Dallas, TX: 1978).

Figure 2-5. PROJECTED U.S. EXHAUSTION DATES OF ULTIMATELY RECOVERABLE PETROLEUM RESOURCES

PETROLEUM TECHNOLOGY

Exploration

Petroleum is found in subsurface cavities or pockets of porous rock surrounded by nonporous rock. Petroleum exploration requires (1) a knowledge of subsurface geologic structures and the types that favor formation of oil or gas pools and (2) methods of obtaining data (primarily through geophysics) about underground formations. The four most common exploration methods are: direct indications, geological and geochemical methods, geophysical methods, and subsurface methods involving borehole logging and sampling.

A direct indication (surface evidence of the presence of petroleum) is typically shown by natural seepage of oil, outcrops of oil-bearing rocks, and various forms of gas seepages. Although the visible presence of hydrocarbons suggests that an area should be explored, it does not necessarily prove that commercial quantities of oil exist.

Geological exploration methods involve the preparation of surface and subsurface maps on which known data are used to extrapolate the probable conditions at locations

where little if any information exists. Surface features (elevations, strikes and dips of rock outcrops, lithological changes) are mapped as clues to subsurface features. Aerial photographs and satellite imagery techniques are valuable for analyzing geological structure in many areas and often are used to locate the most promising areas, which are then mapped in detail by field geologists. As deeper structures are not often reflected by surface features, surficial geologic mapping is usually limited to shallow beds or restricted to new exploration areas.

Three basic forms of subsurface geologic maps are used to predict conditions at depth, including structural contour maps (equal elevation contours), isopach maps (equal bed-thickness contours), and cross sections (profiles of the stratigraphy, structure, and thickness of various geologic units). Besides being useful exploratory tools, subsurface maps are a necessary requirement of any reservoir engineering study.[6,7] Sources of data for subsurface maps are core drillings, stratification tests, and various types of well logs.

Geophysical survey methods are used to collect data on the possible location of subsurface oil deposits from physical measurements made on or near the earth's surface. Geophysical data include variations in the physical properties of subsurface rocks, such as density, elasticity, and magnetic and electrical properties. Geophysics can verify conceptual models of subsurface conditions and rock and mineral distribution by evaluating these rock characteristics. Geophysical methods do not give direct evidence of the occurrence of oil; drilling a hole is still necessary. The value of geophysical surveys is the fact that they reduce the overall risks of exploration drilling.[8]

Basically, the physical principles used in geophysical exploration are magnetism, electricity, gravity, and sound waves. Seismic exploration methods are by far the most popular geophysical tool, accounting for more than 90 percent of all exploration expenditures. The average 1977 cost/mile for a petroleum seismic survey (including data acquisition, processing, and interpretation) in the western hemisphere was $3,161 for land surveys and $741 for marine surveys.[9]

The main sources of basic data for subsurface geology, excepting the data obtained from geophysical surveying, are rock formation samples obtained during drilling. Examination of these samples—drill cuttings, cores, and formation fluids—yields such information as formation lithology and boundaries, elevation of formation boundaries, formation age, formation geometry, location of unconformities, the presence of faults, porosity, permeability, fluid content of porous formations, fluid pressure, formation temperature, and other physical or chemical properties of the system. Analysis of this information provides a better evaluation of a prospect.

Borehole logging and sampling involve drilling a well and using geophysical instruments to log or make measurements at different borehole depths by electrical resistivity, radioactivity, acoustics, or density. In addition, rock formation, or core samples, are collected for both physical and chemical tests and analysis.

Advances in microprocessor technology resulted in the development of a computerized logging system. This system consists of a minicomputer in a logging truck and a microcom-

puter in the logging instrument in the borehole, allowing complete two-way communications between the logging truck and the instrument. Reprogramming the microprocessor allows it to perform necessary mathematical operations and record or display results at the surface. The system can be programmed to measure density and porosity and calculate compensated or true density. The basic system allows great operational flexibility.[10]

The various geologic and geophysical methods can be used to locate favorable structures or environments in which to drill, but wells must be drilled to confirm the presence of hydrocarbons and the size of the reservoir. Two general types of wells can be drilled: field development wells and exploratory wells. Field-development wells are drilled within the boundaries of known reservoirs or a short distance from wells previously completed as producing wells. These wells are drilled to extend the producing area of the known pool or reservoir. Exploratory wells are drilled in search of new producing areas, either above or below known reservoirs or at a considerable distance and entirely independent from known producing areas. These two general types of wells have been further classified by the American Association of Petroleum Geologists, based primarily on drilling objective and the relative position of the petroleum reservoirs or field (see Figure 2-6).

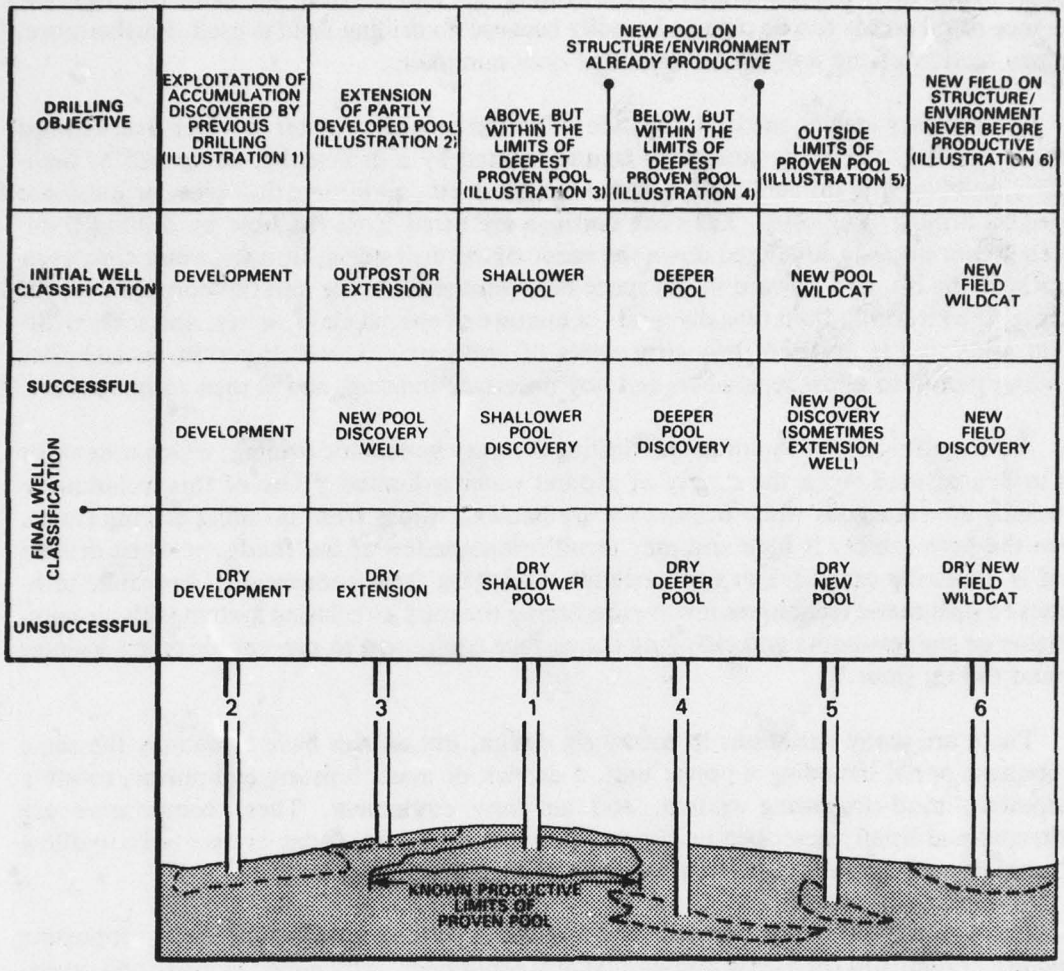
Of all field-development wells drilled in the United States between 1943 and 1957, 78.9 percent were successful. Over the same 15 years, only 19.7 percent of the exploratory wells drilled were successful.[11] (Drilling of exploratory wells peaked in 1956 at 16,207 wells.) In 1977, 9,961 exploratory wells were drilled and the success ratio reached 27 percent.[9,12] According to a recent study, this success reflects both more sophisticated exploratory efforts and a tendency for operators to focus on lower-risk properties until pricing incentives improve.[13] More recent developments in data interpretation and evaluation techniques or processes (computerization and equipment improvements) have improved the success story slightly, though the improvements in the techniques of finding reserves are offset by the increasing difficulty of locating underground petroleum deposits that are large enough for commercial development. Greater depths of drilling now are required to find new reserves, and the more obvious geologic structures have been exploited previously.

Drilling

The total number of wells drilled for oil and gas increased at an average rate of 7.1 percent from 1947 to 1956 when the number of wells drilled peaked at 57,170. In 1977, a total of 44,982 were drilled, but the number of wells drilled that produced oil or gas declined from 69 percent of the total wells drilled in 1947 to a low of 57 percent in 1969. However, this ratio has been increasing since 1973, and in 1977, 67 percent of wells drilled were successful.

Drilling Methods and Equipment

The two primary methods of oil and gas drilling used in the United States are the percussion (cable tool) method and the rotary method. Cost is the major factor in determining which method to use and, while in many shallow areas cable tool drilling can be accomplished less expensively,[14] more than 90 percent of the U.S. oil and gas wells are drilled today by the rotary method.



Source: P. M. Considine, *Energy Technology Handbook* (New York: McGraw-Hill Book Company, 1977).

Figure 2-6. CLASSIFICATION OF PETROLEUM WELLS

In the percussion method, used almost exclusively until 1900, drilling is accomplished by the repeated pounding of a steel bit, which is alternately raised by a steel cable and allowed to fall, delivering sharp continuous blows to the bottom of the hole.[15] Accumulated cuttings and fluid from drilling are periodically removed from the hole by a pump. In an attempt to reduce operating costs, contractors have generally replaced the standard, or stationary, cable tool rig with portable rigs (or have adopted the rotary method). The portable cable tool rigs can drill to 2,286 m and perform workover operations (to restore or increase production) to 3,048 m. Cable tool equipment can also be used for auxiliary purposes such as drilling only the desired footage of the pay section of the hole, remedial and cleanout

work, preparatory work for rotary drilling, and water well drilling for a rotary rig's water supply. While there are limitations on the drilling rate and depth of the cable tool rigs, the presence of oil or gas can be detected readily because no drilling fluid is used. Furthermore, the pay section of the hole is contaminated only minimally.

In the rotary drilling method, the hole is formed by a rotating bit to which a downward force is applied. The bit is connected to and rotated by a drill string, composed of high-quality drill pipe and drill collars. To attain greater depth, additional drill pipes or joints are added as drilling progresses. The rock cuttings are lifted from the hole by drilling fluid, which is continuously circulated down the inside of the drill string, through water courses or nozzles in the bit, and upward in the space between the drill pipe and the borehole. At the surface, the returning fluid (usually mud—a mixture of special clays, water, and several different additives) is diverted through a series of tanks or pits, which permit an adequate standing period to allow separation and any necessary treating, and is then recirculated.

A successful adaptation of rotary drilling is rotary pneumatic drilling, which uses air or gas in lieu of mud when the supply of ground water is limited.[16] Use of this technique is especially advantageous when formations are liable to injury from invading drilling fluids, when the permeability is high and may result in dissipation of the fluids, or when drilling fluid is unusually expensive or not available. Changing from conventional hydraulic techniques to pneumatic techniques involves replacing the mud-circulating system with air compressors or gas regulators and changing the surface equipment to prevent air or gas leakage around the rig floor.[17]

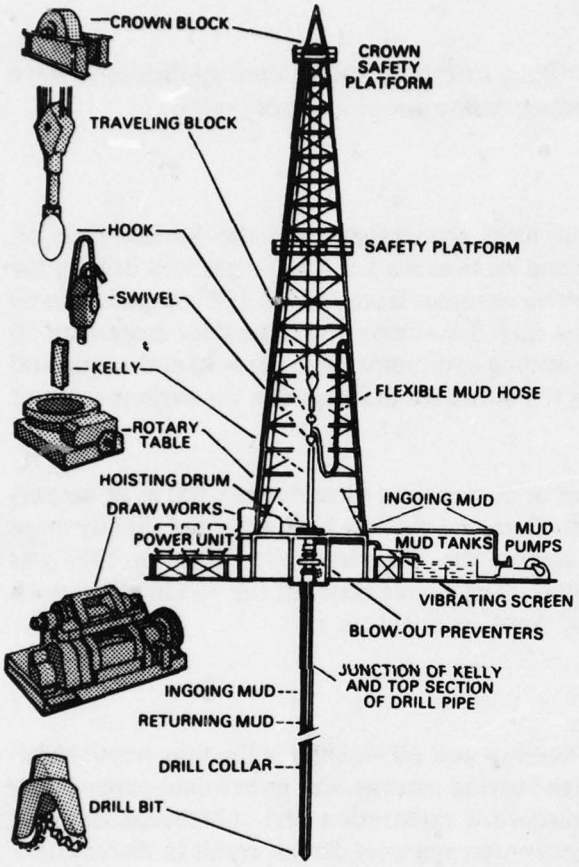
There are many variations in rotary rig design, but all rigs have essentially the same component parts, including a power unit, a derrick or mast, hoisting equipment, rotating equipment, mud-circulating system, and auxiliary equipment. These components are illustrated and briefly described in Figure 2-7. Most rotary rigs today are portable to allow rig mobility and flexibility, thereby reducing drilling costs.

The primary difference between land and water drilling installations is the supporting structure or platform for the rig and its auxiliary equipment, with added emphasis on operational ease, safety precautions, and standby equipment. Both inland-water and offshore (open water) equipment are used, and include the submersible barge, large or small jack-up platforms, drillships, and semisubmersibles.[18]

Among other drilling techniques that have been tested are flame, electric arc, plasma-jet, laser beam, and erosion drilling. These techniques are workable, but uneconomical when compared with methods in general use.[19]

High rig-rental rates have prompted operators to invest in new tools and improved parameter monitoring, and to try new applications for existing products.[2,13] New technology usually requires greater financial downpayment than conventional techniques and generally pays off in rig-time saved or in better productive capacity from wells. Operators, contractors, and service companies are spending more than $40 million/year on drilling research.

One area to improve efficiency and reduce costs is to reduce downhole losses. For



POWER PLANT—Gasoline, diesel, or gas internal combustion engines are the most widely used power units. Power requirements depend on the depth to be drilled.

HOISTING AND ROTATING EQUIPMENT—The hoisting equipment (draw works) raises and lowers the drill pipe and casing. In deep wells, this load can weigh about 200 tons. The drill column is rotated by the rotary table, which grips the drill stem when the hoist is disconnected and pipe sections are inserted or removed. Rotary motion is transmitted to the drill stem through the "kelly" attached to the upper end of the drill column.

DRILL COLLAR AND BIT—The drill bit connects to drill collars at the bottom of the stem. Drill pipe furnishes the needed length of drill string and serves as a conduit for the drilling fluid. Drill collars are heavy walled, large diameter steel tubes, which furnish the compressive load onto the bit, allowing the lighter drill pipe to remain in tension and reduce the tendency of hole misalignment and drill pipe fracture.

Bit design depends on the rock type to be drilled. They may be classified into three general types: drag type, rolling cutter (including jet bits), and diamond.

MUD-CIRCULATING SYSTEM—This system keeps the mud free of rock cuttings or other particulates removed from the hole, as well as maintaining proper physical and chemical characteristics.

AUXILIARY EQUIPMENT—Auxiliary equipment includes such items as traveling blocks, hooks, swivels, blowout preventer equipment, hole-retrieval equipment, and drilling control equipment.

Note: Not to scale.

Source: W. F. Bland and R. L. Davidson, eds., *Petroleum Processing Handbook* (New York: McGraw-Hill Book Company, 1967).

Figure 2-7. TYPICAL COMPONENTS OF A ROTARY DRILLING RIG

example, a large part of the horsepower that goes into drilling is lost due to friction of the drill column (which can be several miles long) against the side of the hole, mud-pressure losses downhole, and the reduction of bit weight by hole drag. Downhole motors offer another method to apply more horsepower to the rock and less to the drilling system. Two downhole motors tested during 1977 are the turbodrill and the electrodrill. Moineau motors and downhole hydraulic motors are two other motor types now under development, and may offer advantages in the near future.[2]

Innovations and improvements in drilling methods, tools, and applications have resulted in safer and more efficient and productive operations in recent years.

Drilling Costs

Costs for drilling and equipping wells have accelerated since the Middle East oil embargo in 1973. Price indices of materials and services used in oil and gas well drilling for 1967 through 1977 are shown in Table 2-4. Price increases from 1967 to 1977 ranged from 63 percent for transportation to 256 percent for fuel. Two items accounting for more than 50 percent of drilling costs are payments to the drilling contractor (36.6 percent) and casing and tubing costs (17.5 percent). Table 2-5 shows the estimated drilling costs for various types of wells in the United States in 1976.

Typical average costs for deep (2,500 m or deeper) and ultra deep (6,100 m or deeper) wells are more than three times the cost of medium and shallow land wells and slightly more than offshore drilling costs. The average cost of the 476 deep wells drilled in 1977 was $417/m with an average well depth of 5,270 m. The average cost of the 50 ultradeep wells drilled in 1977 was $600/m, with an average depth of 6,954 m.

Oil Development Lead Times

The measure of lead time required to develop new oil supplies is the time required between leasing or other access to the resource-bearing acreage and major commercial-scale production. Although lead times reflect successful exploration and subsequent development, it should be recognized that most exploration ventures do not result in discoveries.

The minimum time required to find and develop new onshore oil reserves in the contiguous United States or to develop discovered reserves in the Middle East that have already undergone some development can range from 6 months to 2 years.[4] For such areas as the offshore U.S. Gulf Coast, where exploration takes place in new sectors, but developments are relatively easily integrated with existing operations, new production may be commercially available in 3 to 4 years. In similar situations onshore (such as the southern portion of Canada's Alberta province), lead times range from 1 to 4 years.[4] Areas that are remote from existing producing fields (for example, new areas in the Middle East) or close to existing production facilities but involve technically difficult operating conditions (for example, Alaska and the North Sea) may require 5 to 10 years for exploration and development.[4]

In frontier areas, such as the outer continental shelf off the U.S. East Coast or the harsher Arctic where conditions are difficult and the total infrastructure has to be

Table 2-4. AVERAGE PRICE INDICES OF WELL DRILLING MATERIALS AND SERVICES, 1967-1977[a]

Material or Service	Weight (Percent of total well cost)	Index											Percent Change 1967-77
		1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977[b]	
Payments to drilling contractors	36.6	48.8	53.6	58.1	60.6	62.8	70.7	76.9	100.0	114.8	131.1	149.2	205.7
Purchased items													
Road and site preparation	4.1	65.4[c]	68.5[c]	72.4[c]	76.6[c]	82.8[c]	87.7[c]	93.2	100.0	110.8	119.4	128.7	96.8
Transportation	3.9	75.9	75.9	76.7	80.0	85.1	87.4	90.1	100.0	108.8	115.4	123.6	62.8
Fuel	1.1	46.0[c]	44.0[c]	44.4[c]	47.8[c]	49.5[c]	50.1[c]	57.2	100.0	121.6	141.3	163.9	256.3
Drilling mud and additives	6.9	58.9	61.5	63.7	69.4	75.1	75.2	84.4	100.0	127.7	143.4	151.1	156.5
Well site logging and/or monitoring system	1.2	74.9[c]	77.6[c]	85.3[c]	86.8[c]	87.7[c]	87.7[c]	87.7	100.0	117.5	126.1	136.2	81.8
All other physical tests	0.7	65.6[c]	69.0[c]	73.8[c]	78.5[c]	84.9[c]	84.9[c]	88.4	100.0	120.3	135.4	148.7	126.7
Logs and wireline evaluation services	3.2	65.0[c]	69.1[c]	73.5[c]	79.7[c]	86.9[c]	86.9[c]	89.8	100.0	118.1	137.9	152.5	134.6
Directional drilling services	0.6	71.5	71.5	72.7	76.0	82.6[c]	84.5	87.7	100.0	106.6	116.3	126.2	76.5
Perforation	1.1	74.0[c]	74.6[c]	79.2[c]	86.5[c]	89.6[c]	89.9[c]	89.8	100.0	118.3	131.0	143.1	93.4
Formation treating	3.0	76.2	78.9	82.6	85.0	90.4	90.8	93.4	100.0	126.6	137.3	144.0	89.0
Cement and cementing services	3.7	65.6	69.6	72.7	77.4	86.5	88.0	92.1	100.0	124.6	133.7	137.1	109.3
Casing and tubing	17.5	47.7	51.8	52.0	54.8	65.1	73.8	73.6	100.0	111.2	120.3	132.6	178.0
Casing hardware	0.7	47.7	51.8	52.0	54.8	65.1	73.8	73.6	100.0	111.2	120.3	132.6	178.0
Special tool rentals	3.1	73.3[c]	75.6[c]	78.7[c]	86.3[c]	88.4[c]	88.4[c]	89.8	100.0	115.0	127.2	139.1	89.8
Drill bits and reamers	1.6	62.5	68.7	74.4	80.0	81.0	85.8	87.7	100.0	124.3	134.3	147.9	136.6
Wellhead equipment	1.8	64.4[c]	69.1[c]	72.4[c]	76.0[c]	79.7[c]	80.9[c]	85.6	100.0	120.5	141.5	165.2	156.6
Other equipment and supplies	2.0	63.3	67.4	71.4	75.0	77.7	80.7	84.4	100.0	124.4	138.0	149.9	136.8
Plugging	0.5	58.6[c]	62.6[c]	67.4[c]	74.2[c]	83.3[c]	89.3[c]	93.1	100.0	115.0	122.0	128.0	118.4
Supervision and overhead	2.1	62.9	66.6	71.0	74.1	77.8	82.4	87.8	100.0	110.8	119.5	129.3	105.6
All other expenditures	4.6	65.0	66.6	68.9	71.5	74.1	76.7	81.9	100.0	111.5	118.5	126.9	95.2

[a]Unadjusted for depth.

[b]Preliminary.

[c]Approximate. Figures were derived by rebasing previous composite index (from 1959 = 100 to 1974 = 100). Changes in the number, types, and weights of the elements comprising this composite precluded more exact calculations, i.e., extending the current index (1974 = 100) for each element back to 1966 and applying the approximate weights.

Source: *Petroleum Engineer International,* January 1979.

Table 2-5. ESTIMATED DRILLING COSTS IN THE UNITED STATES, 1976

Type of Well	Total Wells	Average Depth Per Well (ft)	Average Cost Per Well (ft)	Average Cost Per Foot
Oil	16,878	4,044	$ 151,064	$ 37.35
Gas	8,904	5,432	270,375	49.78
Dry hole	13,159	5,152	190,334	36.94
Total	38,941	4,736	191,615	40.46
Offshore[a]	1,028	9,550	1,434,785	150.24

[a]Includes oil, gas, and dry wells.

Source: "Joint Association Survey of the U.S. Oil and Gas Producing Industry," American Petroleum Institute, Independent Petroleum Association of American, Mid-Continent Oil and Gas Association, 1976.

developed, production may not begin for 6 to 12 years.[4] The wide range in time from discovery to on-line production reflects the variability in time required to accomplish each stage of development, including delineating sufficient reserves to justify the very large capital outlays for field development, obtaining environmental permits, and installing logistics support facilities, including major pipelines.

Oil Recovery

Recovering oil (or gas) from a natural reservoir involves displacing the oil from the pore space of rocks. Two fundamentally different displacing mechanisms are used to recover oil from porous rocks: depletion drive and frontal drive.

Depletion drive is a primary oil recovery mechanism whereby the oil is displaced from its reservoir rock by the expansion of the gas it holds in solution under pressure. When pressure is reduced on the reservoir oil through drilling, gas comes out of solution and expels oil from the rock openings. The depletion drive mechanism can combine with a water drive, gas drive, or both (known as segregation drive), contributing to the overall ultimate recovery of the field.

Frontal drive is a primary mechanism wherein the oil is displaced from its reservoir rock by an external driving fluid, either water or gas. A sharp discontinuity exists between the driven and the driving fluid at a well-defined line of demarcation or front. Gravity may or may not play a predominant role in the influencing displacement efficiency and ultimate recovery. If gravity is a predominant factor, it is called gravity drainage.

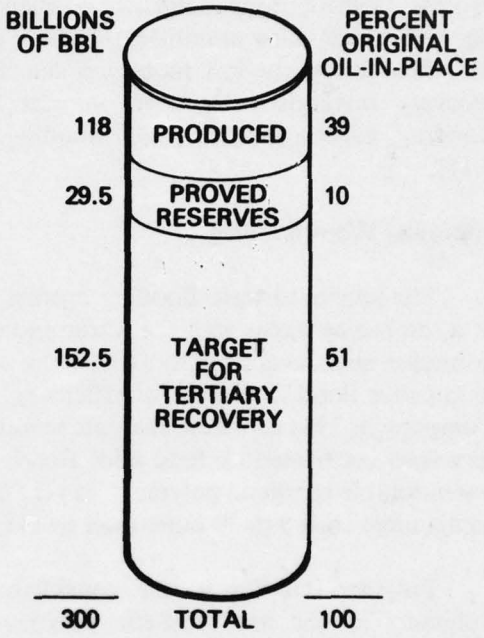
Production of oil using the above mechanisms is called primary recovery. These displacing mechanisms utilize the natural pressures within the reservoir that enable the oil to flow by itself. When the initial drive indices are insufficient to produce the oil naturally or when the reservoir is approaching depletion, artificial lift methods (pumps) are employed.

Reservoir performance of an oil field is characterized by certain essential elements including pressure decline, gas-oil ratio, water-oil rates, productivity index, porosity, and

driving index. One key element related to the flow of oil to the well bore and subsequent production is permeability. If the underground formation is not sufficiently permeable to allow the trapped oil to move toward the well bore, production often will decrease. To improve recovery, many wells are acidized, fractured, or both. Acidizing involves pumping acid into the well to react with calcareous materials in the reservoir rock and, thus, etch out channels to increase the permeability of the reservoir. Fracturing opens up underground channels by force rather than by chemical reaction. A fluid combined with a propping agent (normally sand) is pumped into the well under high pressure to split the rock, creating fissures. When the pressure is released, the fluid flows back out of the well and the propping agents remain behind to keep the fractures open.

Enhanced Oil Recovery

After primary recovery is completed, substantial quantities of oil remain in existing developed oil fields. As shown in Figure 2-8, this unrecovered oil is estimated to be over 60 percent of the original amount in place.[20] Therefore, when a field becomes depleted to a point where it no longer produces economically, secondary recovery methods are applied. These methods involve the injection of water or natural gas into the reservoir to drive oil to the production wells. The injection of water (waterflooding) is the most widely used secondary recovery method. However, to increase the efficiency of the waterflood, a surfactant is added to the water. The use of secondary recovery techniques accounts for approximately one-half of the oil now being produced in the United States. When special agents or advanced techniques are used after the secondary recovery methods have been tried or used, the recovery techniques are termed tertiary recovery. However, since a particular technique may be applied at any time in the life of a reservoir, the term "enhanced recovery" is more commonly used.



Source: U.S. Energy Research and Development Administration, "Management Plan for Enhanced Oil Recovery, Vol. 1—Program Strategy," ERDA 77-15/1, February 1977.

Figure 2-8. U.S. PRODUCTION, RESERVES, AND RESIDUAL OIL-IN-PLACE

The specific recovery technique applied depends on the geologic properties and conditions of the reservoir, the characteristics of the petroleum in the reservoir, and many technical and economic considerations. The first 20 percent of the oil-in-place generally is recovered with primary production technology; secondary recovery makes it possible to recover an additional 10 percent; and tertiary recovery has the potential to recover 10 to 15 percent more. A National Petroleum Council estimate of the potential U.S. crude produc-

tion rate from known fields is presented in Figure 2-9. The extent of the recovery of the remaining oil-in-place depends primarily on crude prices and projected cost. Figure 2-10 shows an estimate of the tertiary oil recovery potential as a function of oil price. Therefore, the incremental ultimate recovery might range from 4 billion bbl at $5/bbl to 33 billion bbl at $25/bbl if the enhanced oil recovery technology was extremely effective.[21]

To be effective, an enhanced recovery method must enhance the mobility of the oil, provide a high volumetric sweep efficiency, and be economically feasible. Furthermore, chemicals and equipment must be in adequate supply. To enhance oil mobility, interfacial tension between the oil and the displacing agents must be considerably lower than the usual oil-water values. High volumetric sweep efficiency, which pertains to the degree of removal of interstitial oil by the injection fluid, is critical to the success of any enhanced recovery process. Control of the movement of displacing agents from the injection well to the producing well is vital. Low mobilities that have good control are inherent in some fluids, whereas for other fluids, the low mobilities can be supplied by means of a thickener.[22] Enhanced recovery methods of current interest are improved waterflooding, micellar-polymer flooding, carbon dioxide (CO_2) flooding, steam flooding and in-situ combustion (Figure 2-11).

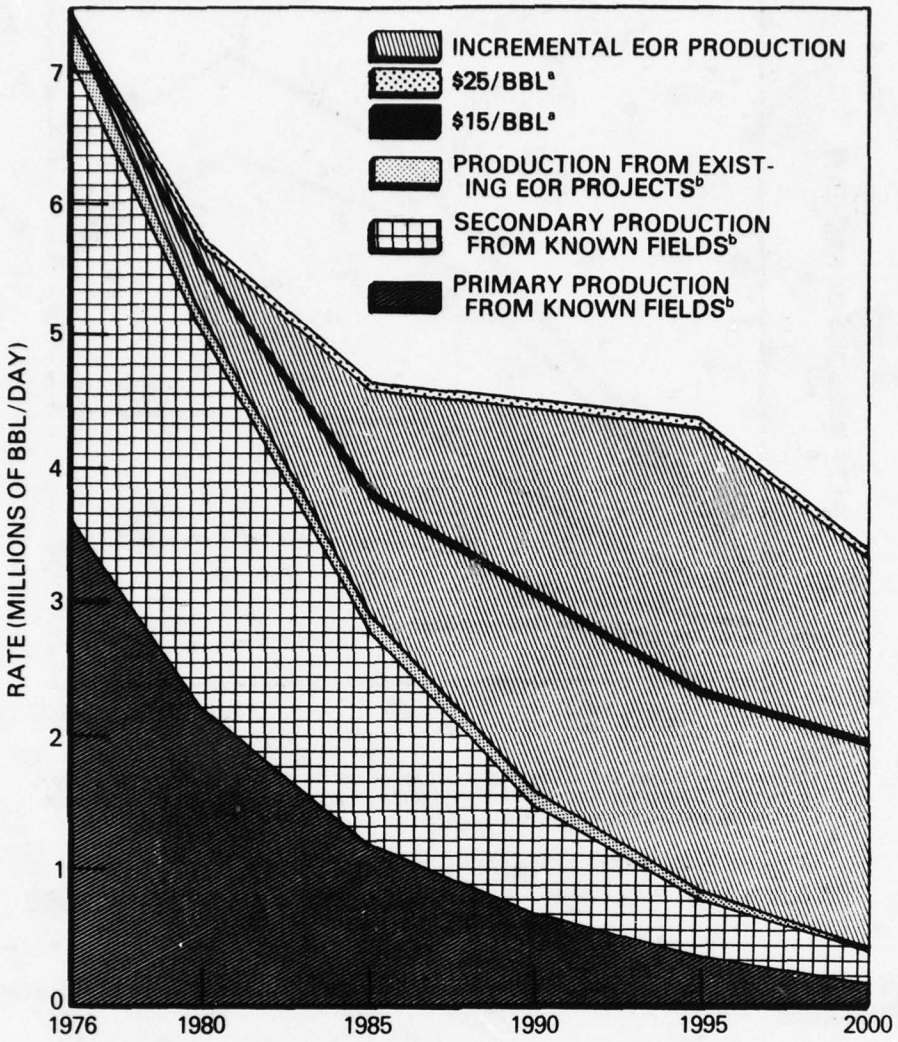
Improved Waterflooding

The improved waterflooding process consists of mixing chemicals such as caustic soda or a thickening agent with the water and injecting it into the injection well. One advanced technique being evaluated by DOE is the use of caustic solution (followed by a salt solution) to improve flood displacement efficiency. Polymers were introduced by the Dow Chemical Company in 1964 as a new low-cost method for improving flood mobility control. Laboratory tests confirmed by field pilot floods have shown that certain high molecular weight, water-soluble synthetic polymers, in very dilute solutions, decrease water mobility in porous media more than 5 to 20 times than would be expected based on the viscosity of the solution.

Polymer flooding is now considered to be an improved or augmented waterflood. Polymers in use are synthetic polymers (polyacrylamides) and biologically produced polymers (polysaccharides). The polymers are added at low concentrations (250 to 1,500 ppm). This method is more likely to be successful in reservoirs containing viscous oils and where the mobility ratio of ordinary waterflooding is adverse.

In addition to increasing the water viscosity, polyacrylamides may expand as they take on additional water in the reservoir and decrease the permeability of the formation to water, thereby reducing the polymer concentration necessary to achieve a given mobility ratio improvement. The magnitude of mobility ratio improvement achievable with polymers decreases with water salinity and divalent ion concentration. Therefore, a source of relatively fresh water, with total dissolved solids less than 10,000 ppm, is desirable for the most effective use of polyacrylamides.

The ability of polyacrylamides to decrease permeability of the formation may be severely reduced by shearing as the polymer is injected. High injection rates, especially



[a]Constant 1976 dollars and minimum DCFROR requirement—10 percent.

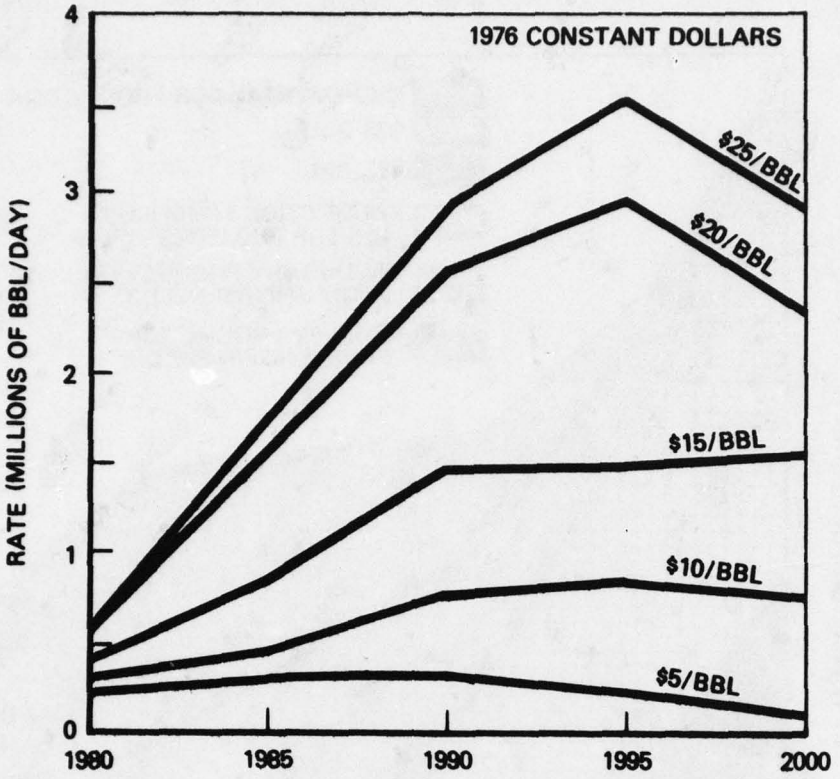
[b]Estimated Producing Rates Based on 31 December 1975, API Reserves.

Note: Production from the following sources is not considered and will be additive to the rates shown:

- Revisions except as included in API "Indicated Additional Reserves" as of 31 December 1975.
- Extensions from realized enlargement of known fields.
- New reservoir discoveries in known fields.
- New field discoveries after 31 December 1975.
- EOR from extensions, new reservoir discoveries, and new field discoveries.
- North Slope, Alaska.

Source: H. J. Haynes and others, *Enhanced Recovery: An Analysis of the Potential for Enhanced Oil Recovery From Known Fields in the United States—1976 to 2000* (National Petroleum Council, December 1976).

Figure 2-9. POTENTIAL OIL PRODUCTION RATE FROM KNOWN U.S. FIELDS

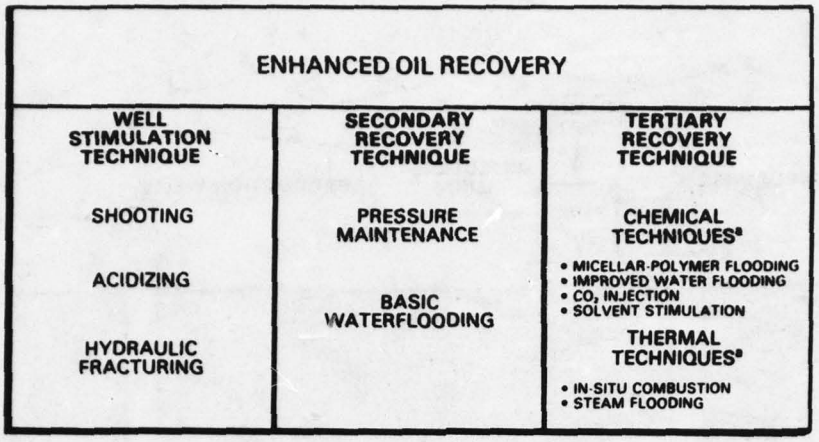


Source: H. J. Haynes and others, *Enhanced Recovery: An Analysis of the Potential for Enhanced Oil Recovery From Known Fields in the United States—1976 to 2000* (National Petroleum Council, December 1976).

Figure 2-10. POTENTIAL OIL PRODUCTION RATE FROM KNOWN U.S. FIELDS BY ENHANCED RECOVERY PROCESSES

through perforations, may be harmful. Moderate injection rates and careful surface handling are required.

In operation, the polymer reduces the ability of the injected water to flow in the reservoir, which improves sweep efficiency. The polymer-water enters otherwise bypassed pore spaces, thus contacting more of the oil and moving it to the producing wells. It has its greatest utility in waterfloods that (1) contain viscous oils (up to about 200 centipoise) and in which the oil saturation is high (15 percent or more above the residual saturation); (2) are moderately heterogeneous; and (3) possess a permeability variation up to a tenfold range. Studies have indicated that polymer flooding generally has little chance of success in a reservoir that has been intensively waterflooded prior to polymer injection. Polymer flooding with polyacrylamides has been, and is being, extensively field tested. Testing of polysaccharides has been limited because they are more expensive per pound and require filtering to prevent well plugging; bactericides are required to prevent bacterial attack and oxygen scavengers are required to maintain effectiveness; and long-term stability of polysaccharides in high temperature reservoirs, greater than 71 °C, has not been demonstrated.



[a]DOD RD&D participation.

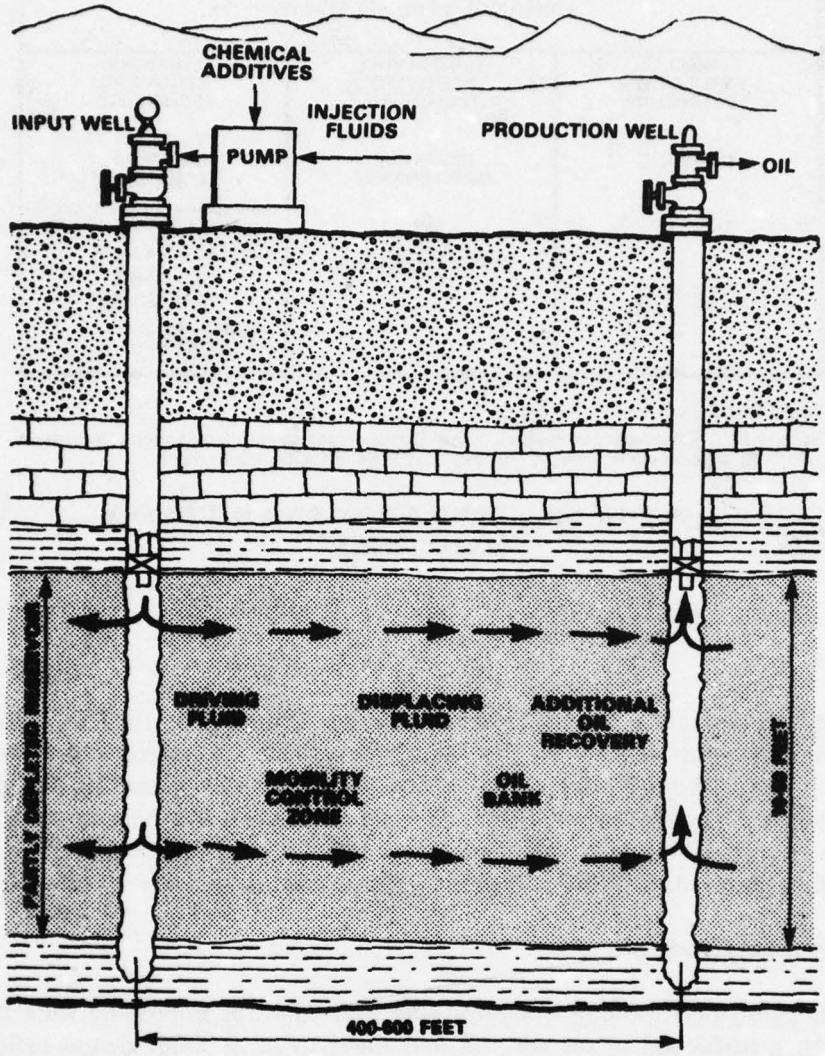
Source: U.S. Department of Energy, "Fossil Energy Research and Development Program of the U.S. Department of Energy, FY 1979," DOE/ET-0013(78), March 1978.

Figure 2-11. OIL STIMULATION AND RECOVERY TECHNIQUES

There are two major waterflooding projects: Wilmington field in California and Ghawar field in Saudi Arabia. At the Wilmington field, 1.5 million bbl of water/day is injected to recover about 3 billion bbl of secondary oil. In this operation, 41 chemicals are used, including 13 corrosion inhibitors, 11 scale inhibitors, five oxygen scavengers, four coagulants, two biocides, two emulsifiers, and two flocculants. At the Ghawar field, 15 million bbl of water/day ultimately will be used in secondary recovery efforts.[23]

Micellar-Polymer Flooding

Micellar-polymer flooding is a promising technique for improving waterflooding. In this process, a surfactant mixes with oil and water to form small groups called micelles. Since each micelle is smaller than the droplets of oil that form in a mixture of oil and water, they are much easier to move through the rock formation. This process is carried out in three stages. In the first stage, the micellar solution is formed and injected into the reservoir. (Before the micellar solution is injected, the reservoir is preflushed with a low-salinity water to reduce the harmful effects of divalent ions, which tend to break down the micelles.) The second stage is the injection of a mobility control buffer, a polymer solution tailored to the formation permeability and the density and viscosity of the micellar mixture. The third stage is the injection of water to move the polymer solution, the micellar solution, and the oil bank toward the producing wells. This process is shown in Figure 2-12.



Note: This diagram represents carbon dioxide, micellar-polymer, and hydrocarbon miscible recovery techniques.

Source: U.S. Department of Energy, "Fossil Energy Research and Development Program of the U.S. Department of Energy, FY 1979," DOE/ET-0013(78), March 1978.

Figure 2-12. MICELLAR-POLYMER FLOODING PROCESS

The micelles are composed of a petroleum sulfonate as the principal surfactant, a solubilizer (such as an alcohol or ether sulfate), water, and oil. The mobility control buffer used is a polyacrylamide or polysaccharide. The molecular weight of these materials must be designed for the reservoir permeability to provide high sweep efficiency. The concentration of the polymer in water is tailored to a high viscosity near the oil-buffer interface and a viscosity nearly that of water at the water-buffer interface.

A large amount of chemicals is used in this type of flooding technique. Estimates by the Gulf Universities Research Consortium indicate that, for each barrel of oil produced using this enhanced recovery technique, about 4.5 kg of surfactant (100 percent active basis), 1.4 kg of alcohol, and 0.5 kg of polymer will be required. Assuming a response time of 4 years from project start to oil production response, chemical demands associated with surfactant flooding could reach 331 million kg of surfactant, 99 million kg of alcohol, and 23 million kg of polymer.[22]

Figure 2-13 shows the location of the 24 active and four planned surfactant recovery projects in the United States.[24] Because of the complex nature of these tests and the fact that a lot of these tests have been initiated recently, the results and evaluations of the various technologies are sparse.

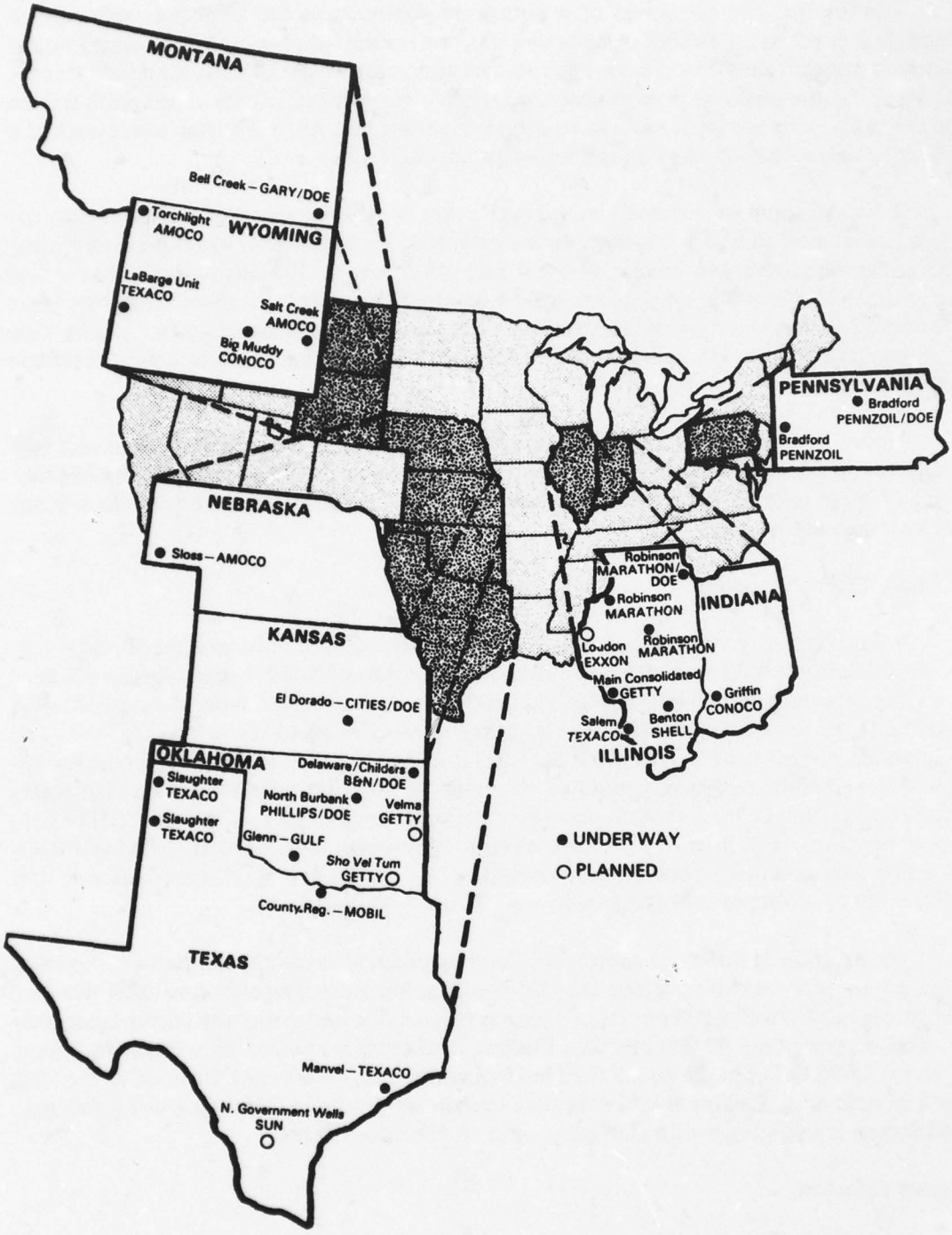
Carbon Dioxide Flooding

An alternative technique that may be less expensive than micellar-polymer flood is carbon dioxide injection (see Figure 2-12). However, this type of flood is generally less efficient than the micellar-polymer process and is applicable to a different type of reservoir. The liquid CO_2 mixes effectively with oil and easily moves the oil to the producing well. The primary disadvantage of CO_2 floods is that the liquid CO_2 tends to sweep through the formation faster than the oil, leaving more oil than does the micellar-polymer process. However, this technique can be used in reservoirs where the micellar-polymer process cannot. The CO_2 flood performs best in reservoirs that already have been waterflooded. Therefore CO_2 flooding may eventually assist in the production of 9 billion bbl of oil out of the over 100 billion bbl of oil-in-place in California, west Texas, and Appalachia.

The location of nonhydrocarbon gas flooding projects in the United States is shown in Figure 2-14. Most of these projects are CO_2 flooding, but a few are conducted using flue gas, air, nitrogen, and acid gas. Four large-scale gas projects are under way with a combined production of more than 90,000 bbl/day. Phillips Petroleum is conducting a large CO_2 flood covering 12,960 acres in the Aneth field in Utah and has begun a large CO_2 flood at the Lick field in Arkansas. Phillips is initiating tests in tight sandstone in Oklahoma using flue gas, and Exxon is initiating a new flue gas project at Hawkins, Texas.[24]

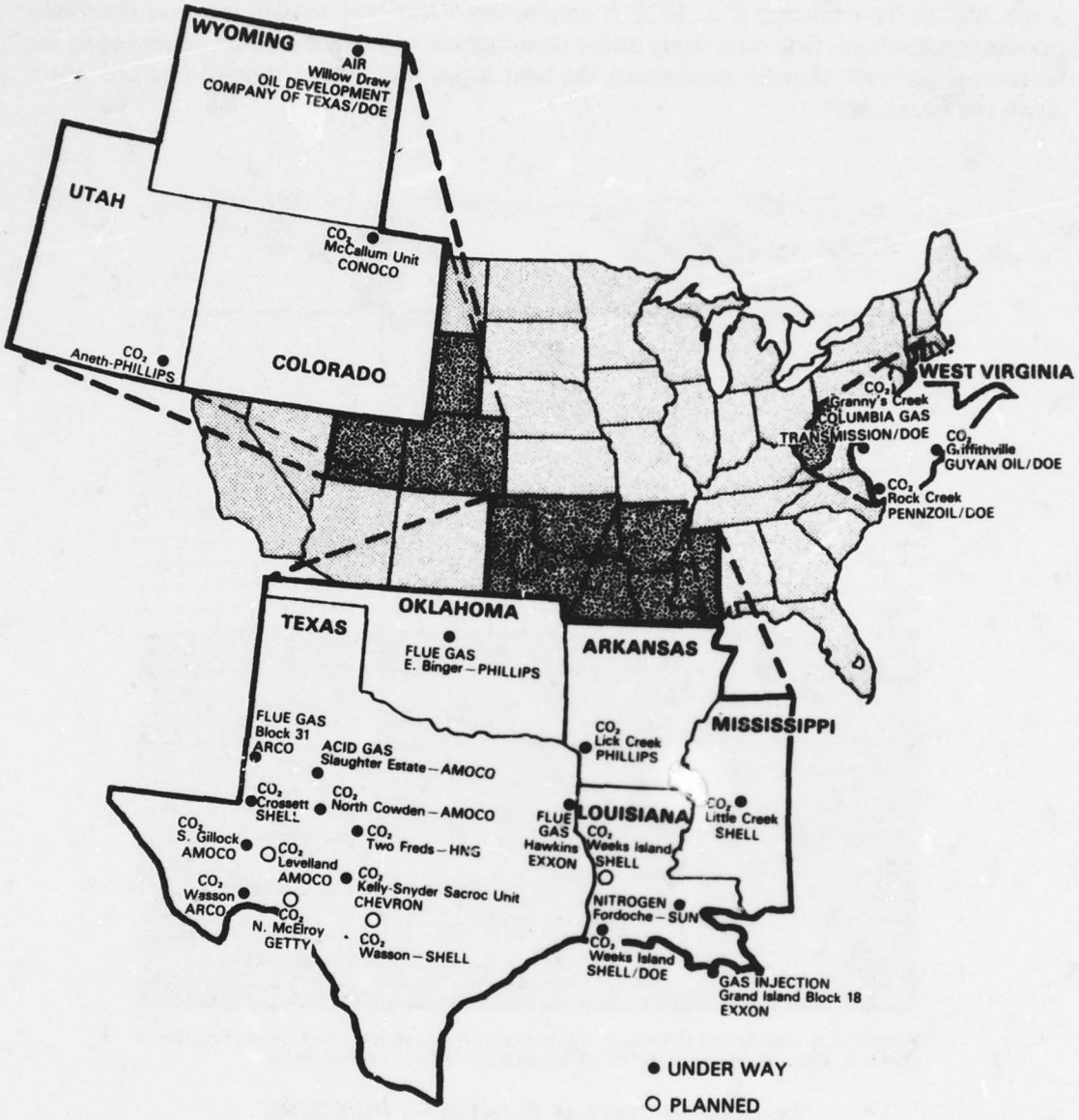
Steam Flooding

One of the major problems in recovering heavy oils is their slow movement through the formation due to the high viscosity and low API gravity of these oils. The heat from steam flooding reduces the viscosity and the specific gravity of the oil, thereby decreasing its resistance to flow. A schematic diagram of the steam flooding process is presented in Figure



Source: "Growth Masks Enhanced Oil Recovery," *Oil and Gas Journal,* 27 March 1978.

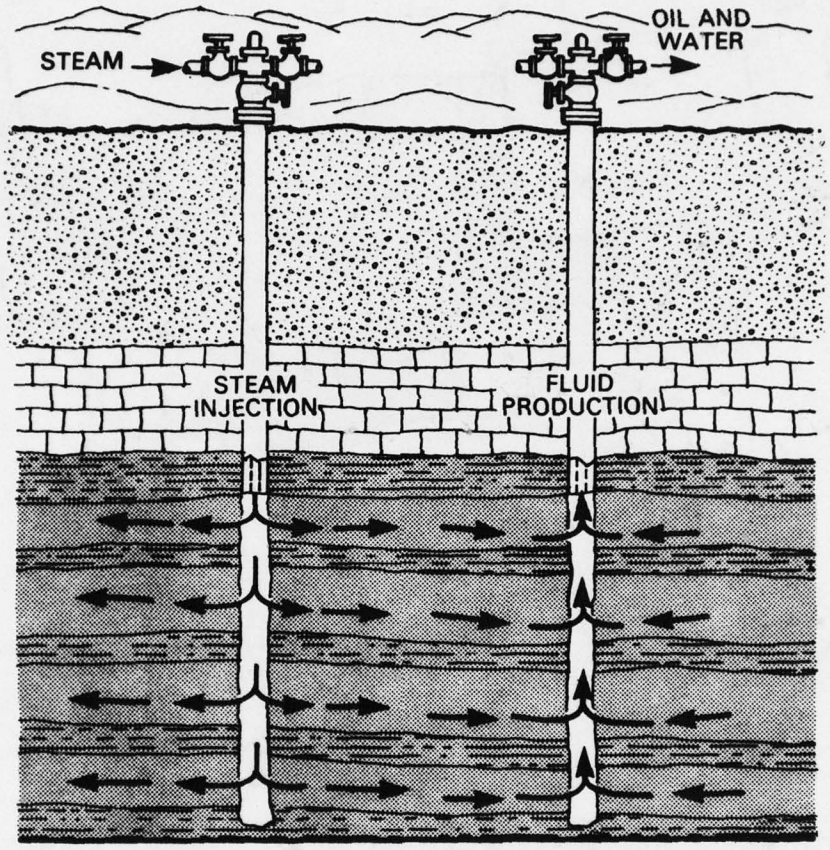
Figure 2-13. SURFACTANT RECOVERY PROJECTS



Source: "Growth Masks Enhanced Oil Recovery," *Oil and Gas Journal,* 27 March 1978.

Figure 2-14. NONHYDROCARBON GAS INJECTION PROJECTS

2-15. In the process of steam flooding, however, the steam loses a lot of its energy as it passes down the borehole to the reservoir and, after it is transferred below 914 m, the steam is too cool to have much effect. DOE is conducting R&D programs to improve the steam flooding technology. One such study under investigation is to place a steam generator at the bottom of the well, thereby minimizing the heat losses incurred in transferring the steam down the borehole.[25]



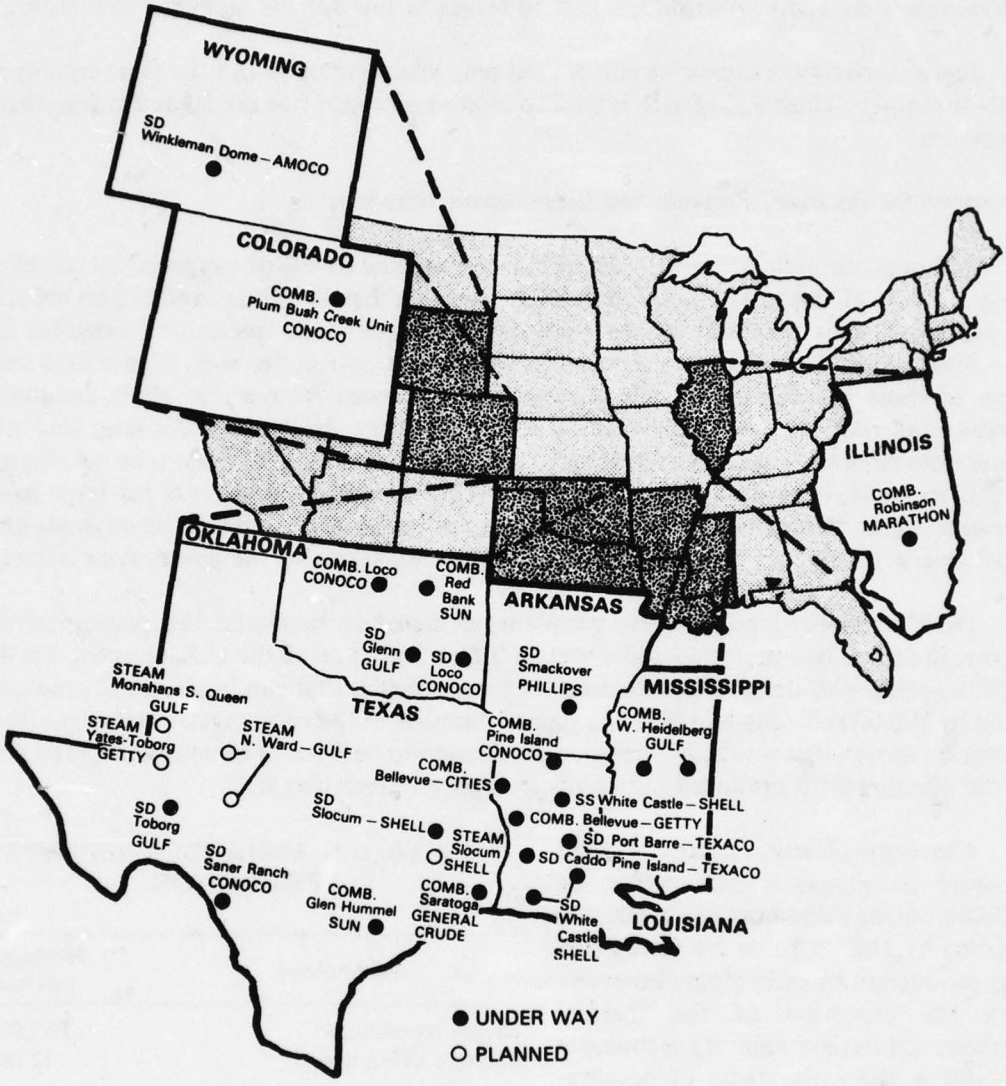
Source: U.S. Department of Energy, "Fossil Energy Research and Development Program of the U.S. Department of Energy, FY 1979," DOE/ET-0013(78), March 1978.

Figure 2-15. STEAM FLOODING PROCESS

Steam flooding projects, both thermal soak and steam drive, in the United States, are presented in Figure 2-16. Most of the projects are located in Texas, Louisiana, and Oklahoma. The majority of those in Texas are still in the planning stages.[24]

In-Situ Combustion

In-situ combustion is a totally different approach to reducing the viscosity and specific



Note: SS—steam soak; SD—steam drive; and COMB.—combustion.

Source: "Growth Masks Enhanced Oil Recovery," *Oil and Gas Journal,* 27 March 1978.

Figure 2-16. THERMAL PROJECTS

gravity of heavy oil-in-place by the application of heat. In this process, a portion of the oil is ignited at the injection well (air is injected through the injection well to provide the necessary oxygen for combustion). As the flame front and combustion gases move toward the production well, the oil bank is heated (see Figure 2-17). In addition, the combustion gases increase the reservoir pressure, enhancing the movement of less viscous, higher gravity oil toward the production well. The heavier oil left behind serves as fuel for the moving flame front.

In-situ recovery is expensive and is used only when the oil cannot be recovered by any other technique. This method also is used to recover oil sands (tar sands) and is described in Chapter 6.

Enhanced Oil Recovery Projects and Government Activities

Although estimates of how much oil can be obtained by use of enhanced oil techniques range from 15 billion to 110 billion bbl, DOE estimates that 40 billion to 60 billion bbl could be produced. This potential recovery constitutes a significant fraction of available U.S. petroleum reserves and justifies the numerous projects now under way. Figure 2-18 shows some of these programs.[25] DOE's program for enhanced recovery of oil is designed to develop and transfer new technology to private industry. High risks and long lead times require the federal government to provide incentives for industry to undertake development of this technology. In addition, current pricing conditions, requirements for large capital investments, and uncertainties about the successful outcome of some of the methods under development all indicate that a substantial developmental role by the government is needed.

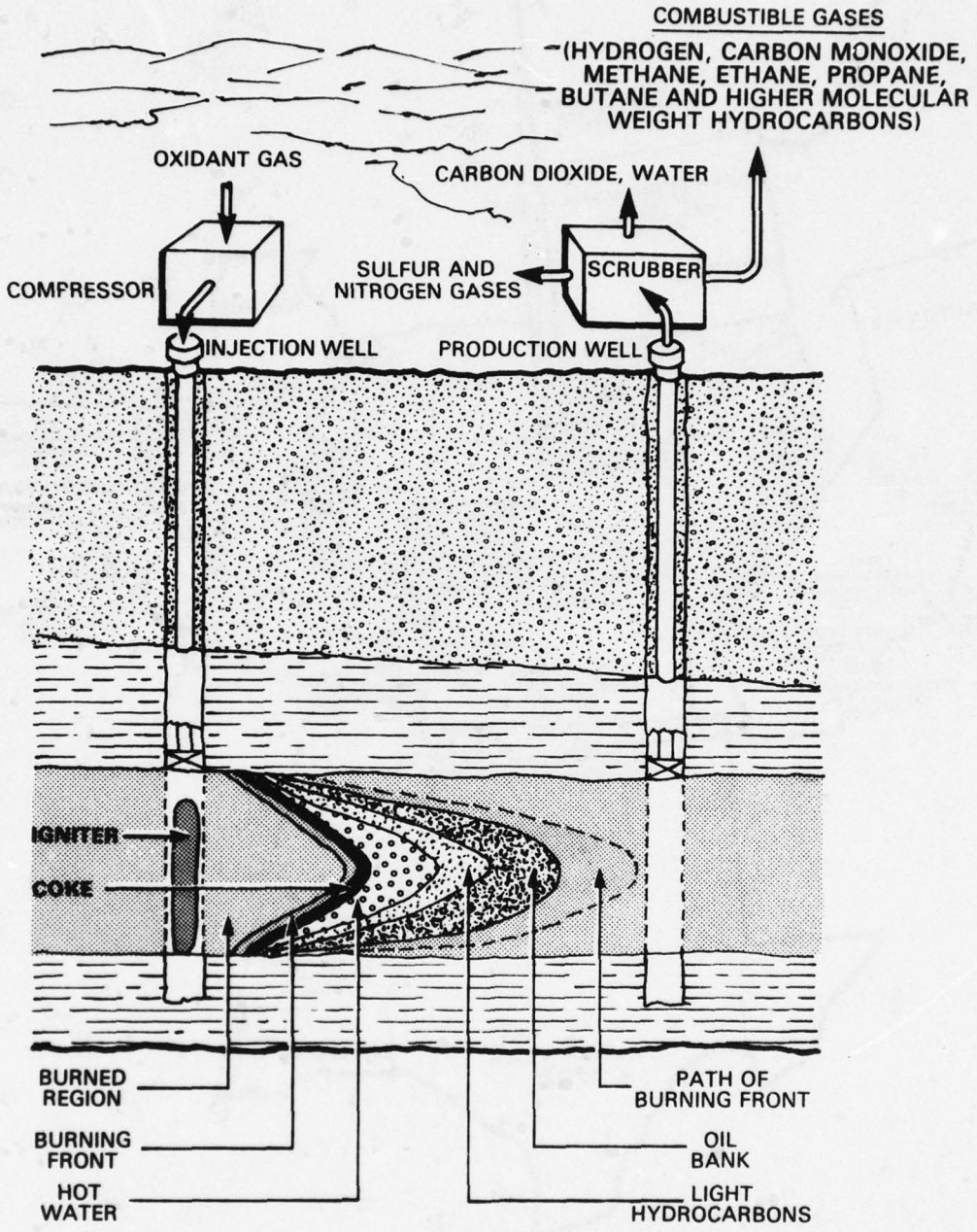
DOE's enhanced oil recovery program, designed to maximize the participation of private industry, is expected to add about 15 billion bbl of oil to the U.S. reserves. Further, DOE's goals are to develop and demonstrate technologies that can increase the production of oil by 800,000 bbl/day by 1985. The typical duration of the various projects ranges from 2 to 5 years for the first results of increased production to be seen, or to determine if the worth of the additional oil produced outweighs the cost of producing it.[25]

Current production using enhanced recovery techniques is estimated to be 373,000 bbl/day and may reach 600,000 bbl/day by 1990.[24] Table 2-6 shows current production by technology; however, with the exception of the thermal methods, all tertiary recovery techniques are still in the early stages of development, and no one technology has demonstrated any applicable performance or cost advantage over the others. Furthermore, all technologies are not applicable to all reservoirs. Although industry is moving as fast as technology and money permit in exploring enhanced recovery methods, most producers agree that it will be in the late 1980s before the United States can expect any significant incremental crude production resulting from enhanced recovery technology.[26]

Table 2-6. U.S. ENHANCED RECOVERY PRODUCTION

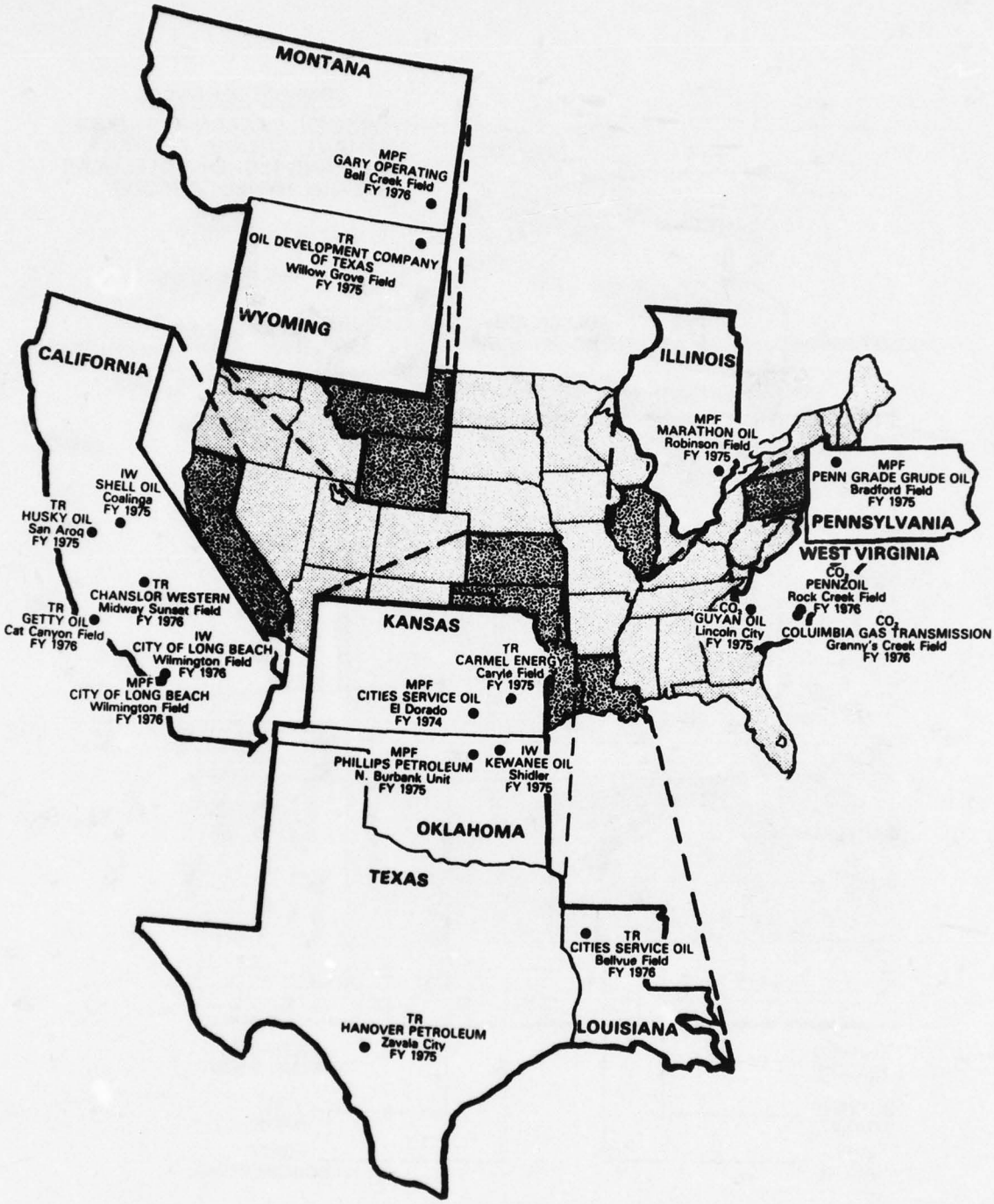
Technology	Production (bbl/day)
Steam techniques	250,000
In-situ combustion	10,000
Chemical (micellar-polymer, improved waterflood, etc.)	3,000
Gas flood (CO_2, N_2, flue gas, air)	110,000
Total	373,000

Source: "Growth Masks Enhanced Oil Recovery," *Oil and Gas Journal*, 27 March 1978.



Source: U.S. Department of Energy, "Fossil Energy Research and Development Program of the U.S. Department of Energy, FY 1979," DOE/ET-0013(78), March 1978.

Figure 2-17. RECOVERY BY IN-SITU COMBUSTION



Note: Oil Reserves: H—high (greater than 7 billion bbl); M—medium (between 1 and 7 billion bbl); and L—low (less than 1 billion bbl).

Enhanced Recovery Technique: MPF—micellar polymer flooding; CO_2—CO_2 flooding; IW—improved waterflooding; and TR—thermal recovery (in situ combustion and steam flooding).

Source: U.S. Department of Energy, "Fossil Energy Research and Development Program of the U.S. Department of Energy, FY 1979," DOE/ET-0013(78), March 1978.

Figure 2-18. DOE/CONTRACTOR ENHANCED OIL RECOVERY PROJECTS

Enhanced Oil Recovery Projects in Other Countries

Thermal recovery techniques account for about 56 percent of Canada's enhanced oil recovery program. A large thermal project in Indonesia is recovering 4,000 bbl/day from the Duri field. Several high-pressure miscible gas-injection projects on a large scale are under way in North Africa, and a large project is planned for Iran.

Trinidad has five projects using thermal techniques and two hot waterfloods. In Mexico, most thermal recovery plans have recently been replaced with major efforts directed toward the development of the lighter cretaceous oil that was recently discovered. The Intrisar "D" field in Libya uses gas injection flooding, with no significant results to date. Colombia has an 18-well steam soak project in Cocorna Field, and Brazil has a pilot test in the Carniopolis field using a polymer flood. The result of this pilot test is an oil production of about 200 bbl/day.[23]

Petroleum Characteristics and Feedstocks

Petroleum as it comes from the well is called crude oil, and as such is not particularly useful. It must undergo a considerable amount of processing in a refinery to separate it into usable products such as gasoline and diesel fuel.

Petroleum is composed of mixtures of hydrocarbons of various types. The composition by weight of the various elements in petroleum is relatively uniform, and generally falls within the following ranges:

Element	Weight Percent
Carbon	84–87
Hydrogen	11–14
Sulfur	0–2
Nitrogen	0–0.2

The physical properties of crude oils vary considerably; therefore, the specific properties of each oil must be evaluated before it is processed in a refinery. Crude oils have been classified as paraffin base, cycloparaffin (naphthene) base, asphalt base, or mixed base. In addition, there are some crudes from the Far East that have up to 80 percent aromatic content and are classified as aromatic base oils.[27]

Because each crude contains a number of different hydrocarbons, it is difficult to classify the crude in the above categories, especially in borderline cases. Therefore, a different approach has been developed, using characterization factors that are correlations between yield and the aromaticity and paraffinicity of the crude oil. Two of the most widely used classifications are the UOP characterization factor (K_w) and the U.S. Bureau of Mines (BOM) correlation index (CI).[27]

The characterization factor is defined as the cube root of the mean boiling point (°R) divided by the specific gravity at 15.6°C. This factor ranges from less than 10 for highly aromatic crudes to almost 15 for highly paraffinic crudes. However, most crudes have a much narrower range (10.5 for highly naphthenic crudes to 12.9 for a paraffinic crude).

BOM's CI is valuable in evaluating individual fractions of a crude oil. The CI scale is based on straight-chain paraffins having a CI value of 0 and benzene having a CI value of 100. Therefore, the lower the CI value the greater the concentration of paraffins, and the higher the value of CI the greater the concentration of cycloparaffins and aromatics.

Based on the K_w and/or CI factors and the results of other tests, the various crudes entering the refinery can be blended to produce a final feedstock that is near in quality to that for which the refinery was designed.

Two other properties, sulfur content and specific gravity (generally API gravity), also are used to specify crudes, as they have the greatest influence on the value of crude oil. (API gravity runs from 0, equivalent to specific gravity 1.076, to 100, equivalent to specific gravity 0.6112.) The sulfur content, measured as percent by weight, varies from less than 0.1 percent to greater than 5 percent. "Sweet" crude has less than 0.25 percent sulfur, and "sour" crude, which requires more extensive processing, has more than 0.5 percent sulfur. The sulfur content and gravity of some typical crudes are given in Table 2-7.

Because of the different properties of crude oil produced in different countries, the number of barrels of crude/metric ton varies. Figure 2-19 shows the average number of barrels of crude oil/metric ton by country, as a function of API gravity.

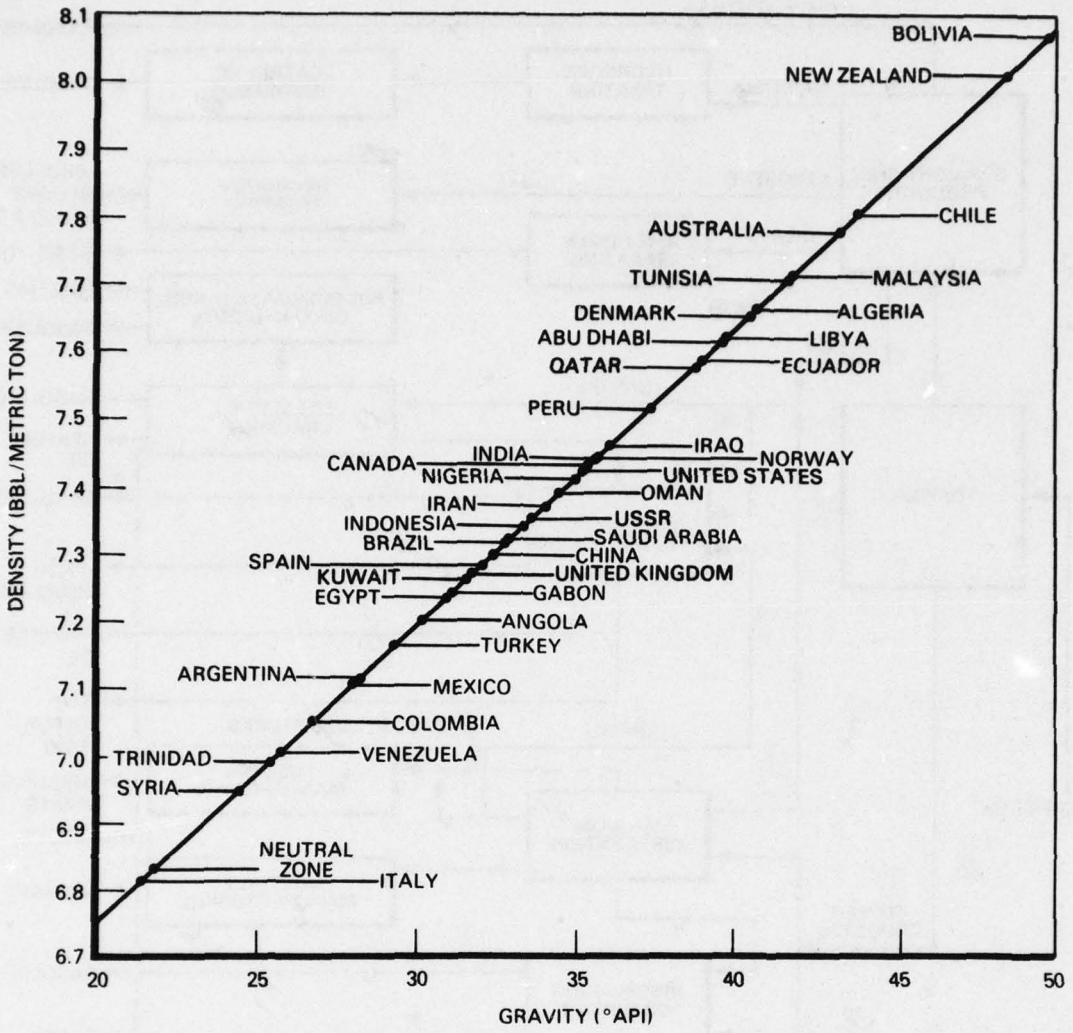
Table 2-7. AVERAGE GRAVITY AND SULFUR CONTENT OF U.S. AND FOREIGN CRUDES

Crude	Gravity (°API)	Sulfur Content (Weight percent)
United States		
California average	26.2	1.05
East Texas	38.0	0.26
Typical Gulf Coast	22.0	0.19
West Texas	36.0	1.38
Average United States	34.7	0.75
Foreign		
Indonesia	35.0	0.09
Iran		
Light	34.0	1.35
Heavy	31.0	1.60
Kuwait	31.0	2.50
Nigeria	34.0	0.16
Saudi Arabia		
Light	34.0	1.70
Berri	39.0	1.16
Heavy	27.0	2.85
Medium	31.0	2.40
Venezuela	26.0	1.52

Sources: Central Intelligence Agency, 1977; and W. L. Nelson, *Petroleum Refinery Engineering,* 4th ed. (New York: McGraw Hill Book Company, 1969).

Refining

About 2,500 products are currently produced wholly or in part from petroleum in addition to more than 3,000 petrochemicals. Petroleum products supply power for a vast transportation network, factories, and farms; heat for homes and large buildings; lubricants for many industries; material for highway, road, and street networks; and feedstock for petrochemicals. The major portion of petroleum's total market in the United States is for motor and aviation gasoline (44 percent); the second market is fuel oils (32 percent); other portions are used for liquid petroleum gas (6 percent), jet fuel (5 percent), petrochemical feedstocks (5 percent), asphalt (3 percent), lubricating oils and greases (2 percent), and a host of other products.

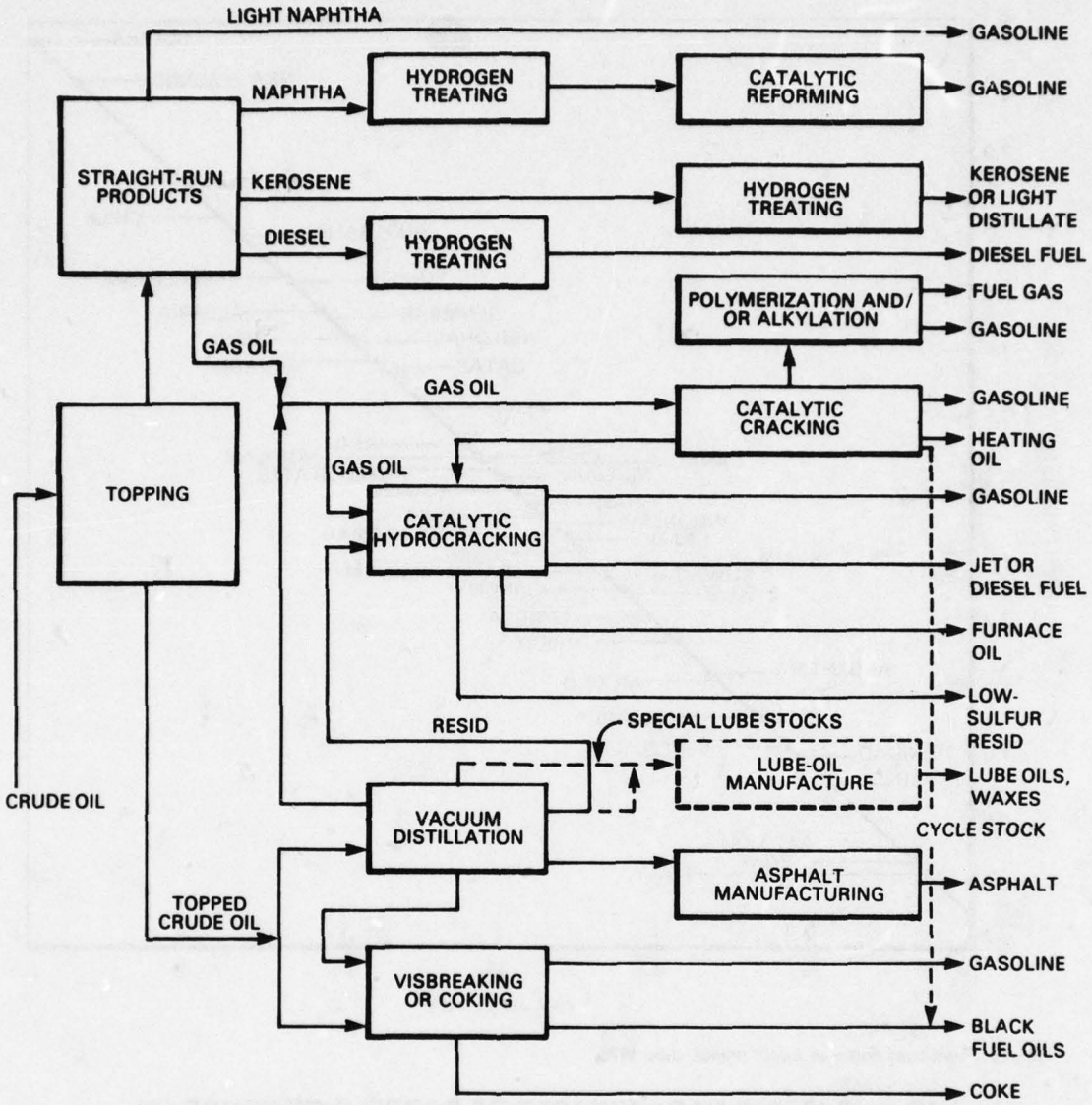


Source: *Petroleum Engineer International,* July 1978.

Figure 2-19. AVERAGE NUMBER OF BARRELS OF CRUDE OIL PER METRIC TON BY PRODUCING COUNTRIES

Refinery Processes

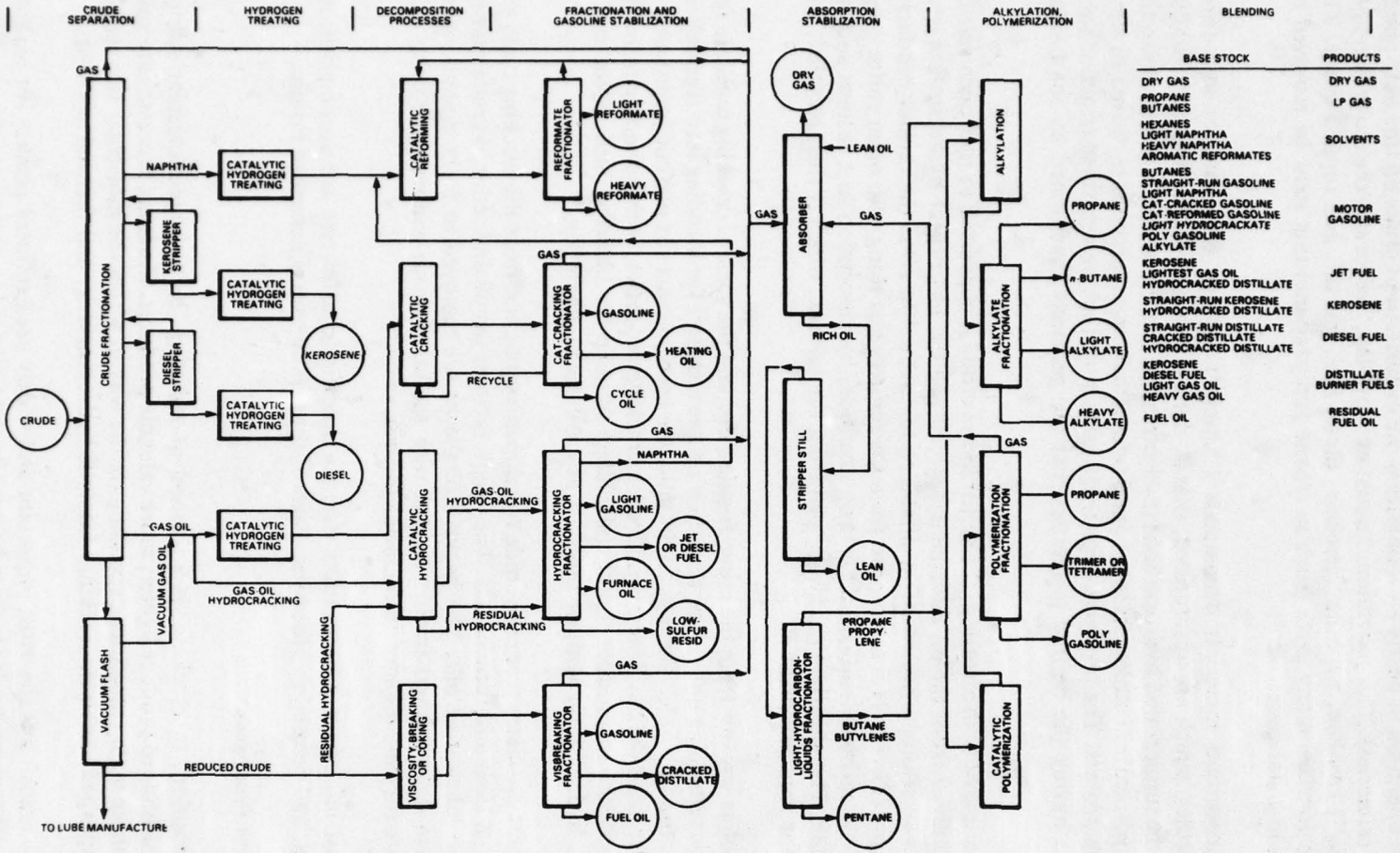
Each refinery has its own unique processing scheme determined by the crude oil to be processed and the product demand. The optimum flow pattern for any refinery is dictated by economic considerations. Certain operations are common to most general refinery flow plans; these are indicated in Figure 2-20. The simplified diagram fails to show fully the interdependence of the units but the heat and by-products from one unit generally are used elsewhere in the refinery.



Source: *Kirk-Othmer Encyclopedia of Chemical Technology,* 2nd ed., Vol. 15 (New York: John Wiley and Sons, 1978).

Figure 2-20. BASIC REFINERY OPERATIONS

Figure 2-21 shows a typical flow sequence for recovering the straight-run gasoline or the lighter fractions of crude oil, and the decomposition ("cracking") of the heavier materials to further increase the yield of gasoline. (A similar flow plan could be shown for the manufacture of lubricating oils.) The processing scheme is divided into seven separate parts, and the relationship between them is also indicated. The bottom product from the crude fractionation unit may be processed for lubricating oils; vacuum flashed (as shown in Figure 2-21) to produce a vacuum gas oil (for feed to catalytic cracking or hydrocracking plants) and a viscous reduced crude oil (which may be subjected to viscosity-breaking or coking); or mixed with a lighter oil to produce residual fuel oil.[28]



Source: *Kirk-Othmer Encyclopeida of Chemical Technology,* 2nd ed., Vol. 15 (New York: John Wiley and Sons, 1978).

Figure 2-21. FUEL-TYPE REFINERY (MAINLY GASOLINES, DISTILLATES, AND BLACK FUEL)

The first operation in nearly all refineries is the distillation of crude oil (the only operation in some refineries). This operation, known as "topping," separates the crude into light ("straight-run") gasoline, naphtha, kerosine, diesel fuel, gas oil, and topped crude. The light gasoline contains many gases (such as ethane and propane) that must be removed by fractionation in a stabilizer.

All hydrocarbon materials decompose ("crack") at high temperatures and form smaller molecules, which are unsaturated, that is, deficient in hydrogen. Therefore, adding hydrogen to the unsaturated hydrocarbons (hydrotreating processes) and breaking down the large heavy hydrocarbon molecules into lighter ones (cracking processes) are the major steps in the refining process. The products from these units must then be separated (fractionated) into products having the desired properties that are generally determined by the boiling point range.

In the course of hydrotreating, the sulfur in the crude is converted to hydrogen sulfide (H_2S) and removed from the oil into the gas stream. In the absence of hydrotreating processes, other sweetening processes are available to remove sulfur from the various products, converting it to H_2S. The H_2S is removed from the refinery gas along with other sulfur compounds, such as carbonyl sulfide and carbon disulfide, by absorption in a solvent such as diethanolamine. The absorbed gas is stripped from the solvent, which is then recycled, and sent to a sulfur recovery plant.[29]

The gasoline streams from the crude fractionator and the various cracking units are fed to the catalytic reforming unit to improve their octane numbers for blending into regular and premium gasolines for sale. The alkylation units are used to react the olefinic hydrocarbon gases (propylene and the butylenes) produced in cracking processes, with isobutane from the reforming processes to produce liquids (alkylates) suitable for blending into motor fuels. Sulfuric acid, hydrofluoric acid, or both act as catalysts in alkylation.[28]

The middle distillates from the crude fractionation unit and from the cracking units are blended into jet fuels and furnace oils. The heavy vacuum gas oil and reduced crude may be processed into lubricating oils. The heavy asphaltenes are removed to form asphalt; these stocks are then dewaxed and further treated with special clays to remove their color and stability before they are blended into lubricating oils.[27,28]

The most important process units that are specific to refineries are decomposition, hydrotreating, and reforming processes. Each of these processes is described briefly.

Decomposition Processes

Decomposition, or cracking, is a method of reducing the average molecular size of heavy hydrocarbons to produce lighter, more valuable products. Cracking processes are subdivided into three main categories depending on the way in which the molecular size reduction is accomplished: catalytic cracking, catalytic hydrocracking, and thermal cracking.

Catalytic cracking is the most important and widely used refinery process for making gasoline and other light products from heavy oils. Hot oil feed is contacted with a suitable

catalyst in a continuously circulating system. As the heavy oil is cracked, lighter oils and hydrocarbon vapors are formed, and carbon is deposited on the catalyst. After the catalyst is separated from the oil and vapor products, it is sent to a regenerator where air burns the carbon from the catalyst pellets. Hot, regenerated catalyst is then returned to contact the oil feed and renew the cycle.

Catalytic hydrocracking combines cracking of heavy oils with hydrotreating (reacting the oils with hydrogen at high pressure). Because this process can operate at pressures up to 2,000 psig and use a high concentration of hydrogen, gasoline and light products can be produced from heavier feedstocks than those used in normal catalytic cracking. Furthermore, hydrocracking has greater flexibility in producing varying ratios of motor fuels to middle distillate fuel oils.

Most thermal cracking units, which use heat alone to cause decomposition, have been replaced by catalytic cracking or hydrocracking processes, which are more effective for producing lighter hydrocarbon liquids. Viscosity-breaking (or visbreaking) and coking processes are the only thermal cracking units still in use.

Visbreaking, a mild form of thermal cracking performed at 475 °C and 240 psig, breaks many of the feed molecules in half. These lighter molecules are collected as light and heavy gas oils, and the residue forms a thick, highly viscous, solid. This solid is cut with some of the light gas oil (low viscosity), producing a lower viscosity gas oil, which is then sent to other units.

Coking, a severe form of thermal cracking (538 °C) eliminates residual fuel oil. The feed—pitch—is sprayed into a hot fluidized bed of coke particles. In the cracking process, more coke is formed, and the low-sulfur coke product is continuously removed. The smaller, or cracked, hydrocarbons are separated from the coke and sent to a fractionation tower, where the gas oil is separated, and the heavier fraction recycled.[27-29]

Hydroprocessing

Hydroprocessing is a generic term for all processes in which the feed to the unit consumes hydrogen. Almost all hydroprocessing is carried out at elevated temperature and pressure over a catalyst. Hydroprocessing operations are subdivided into three categories depending on the way the hydrogen is used: hydrotreating, hydrorefining, and hydrocracking.

The primary purpose of hydrotreating is to convert selectively to a desirable material or eliminate from the system one or more unwanted materials in the feedstock. Hydrotreating can remove sulfur, nitrogen, oxygen, and other impurities from a liquid hydrocarbon feed. As the removal of sulfur is the primary purpose, the process often is called hydrodesulfurization. The sulfur in the hydrocarbon feed reacts with hydrogen over a catalyst, forming H_2S and ammonia. Water is formed from the hydrogen and oxygen. The conditions are such that only these reactions will occur, and are not severe enough to cause hydrogenation of unsaturated hydrocarbons.

Hydrocracking is a decomposition process that takes place at pressures from 800 to 2,500 psig in a hydrogen environment. Generally, hydrocracking processes can accommodate a wider range of feedstocks than can catalytic cracking, and the products are mostly saturated hydrocarbons rather than olefinic as produced by thermal or catalytic cracking processes. While the gasoline products can be blended directly into the gasoline pool, they are not high in octane number. All hydrocracked products are low in sulfur, and the light hydrocarbons have a predominance of branched isomers. The C_4 fraction is accordingly a valuable alkylation feed. Hydrocracking is particularly useful for increasing the production of products such as gasoline and diesel or jet fuel. In hydrocracking, generally more than 50 percent of the feed is reduced in molecular size.

Under mild conditions, such that only about 10 percent of the molecules are reduced in size, the hydrogenation process is called hydrorefining.

Catalytic Reforming

The purpose of reforming is to rearrange or reform the molecular structure of the naphtha hydrocarbons having poor antiknock characteristics to premium quality motor fuels. Reforming produces aromatics from selected naphtha fractions. Because sulfur, nitrogen, and metal compounds poison the noble metal catalysts (such as platinum) used in catalytic reforming, the naphtha feedstock must be hydrotreated prior to entering the reformer. As paraffinic hydrocarbons are converted to aromatics, there is a net production of hydrogen, which can be used for hydrotreating processes within the refinery.[27-29]

Petroleum Products

The current trend in the United States is to produce less residual fuel oil in favor of more gasoline from a barrel of crude oil. Residual fuel oils constitute 35 percent of the market in western Europe. Products other than gasoline and fuel oil play only a small part in the management strategy of refiners. However, while many refineries treat asphalt as a bottom-of-the-barrel product, a few asphalt refineries treat it as a primary product. Other factors that are significant in setting the products from a refinery are the type of crude oil and the immediate market for the product.[30]

Some of the more important products from a refinery are:

- *Light gases.* Low boiling products, in the gas phase at ambient temperatures and pressures, include methane, ethane, propane, butane, and the corresponding olefins. Methane and ethane usually are used as refinery fuels, but also can be used to produce hydrogen or ethylene. Propane and butane are sold as liquefied petroleum gas or used in refinery processing.[30]
- *Gasoline.* Gasolines are a complex mixture of hydrocarbons having a boiling range of 38 to 204 °C. Various components are blended to promote high antiknock quality, ease of starting, quick warm-up, low tendency to vapor lock, and low engine deposits.[30] API reports that 40 types of gasoline are made by refineries, and about 90 percent of the total gasoline produced in the United States is used as automobile fuel, in regular, premium, low-lead, and nonleaded grades. The principal difference between the regular and premium fuels is the antiknock performance.

- *Distillate fuels.* Distillate fuels can be divided into three types: jet fuels, diesel fuels, and heating oils. These products are blended from a variety of refinery streams to meet the particular specifications. In jet fuel, the smoke point is critical; thus the aromatic concentration is limited to 20 percent. The two basic types of jet fuels are naphtha and kerosine. Naphtha jet fuel is produced primarily for the military; kerosine jet fuel is used by the military and commercial aviation. Volatility, ignition quality, and viscosity are the important properties of automotive diesel fuels. Grade No. 1 comprises the class of volatile fuel oils, from kerosine to the intermediate distillates. Fuels within this category are used in high-speed engines in services involving frequent and relatively wide variations in loads and speeds (for example, city buses). Grade No. 2 diesel fuels are used in high-speed engines in services involving relatively high loads and uniform speeds (for example, trucks and tractors). Grade No. 3 diesel fuels are used for railroad diesel engines, the largest single market for diesel fuels. Grade No. 4 covers the class of more viscous distillates and blends of these distillates with residual fuel oils. These are used in low and medium speed engines employed in services involving sustained loads at constant speed, such as large stationary and marine diesel engines. The major use of distillate heating oils in the United States is for central automatic home heating. No. 1 fuel oil is intended for vaporizing pot-type and other burners. No. 2 fuel oil is most commonly used for domestic and small commercial space heating.[30]
- *Residual fuel oils.* In the present-day petroleum refinery, residual fuel oils are largely by-products of operations aimed at maximizing the yield and quality of other petroleum products. Residual fuel oils are widely used in both stationary and mobile steam boilers, and in other industrial applications requiring generation of heat.[30]

The Refining Industry in the United States

In the United States, there are 279 oil refineries with a total capacity of 16,195,755 bbl of crude oil/calendar day. The 105 refineries of 21 major oil companies account for 78.8 percent of the total capacity. (Major companies are those with a crude capacity greater than 1 percent of total industry crude capacity.) The remaining capacity is split up among the small independent oil companies. Ownership of the 113 large refineries (crude capacity of greater than 40,000 bbl/calendar day) in the United States, which account for 87 percent of the total crude capacity, is shared by 50 companies, and no company owns more than 9 large refineries. The greatest capacity owned by any one company is less than 10 percent of the total. Tables 2-8 and 2-9 give an overview of the U.S. refining industry.[31]

The largest refinery in the United States is Exxon's refinery at Baton Rouge, Louisiana, with a crude capacity of 510,000 bbl/calendar day. The largest refinery in the world is the Hess Company refinery, located at St. Croix in the Virgin Islands, with a capacity of 728,000 bbl/calendar day.

TRANSPORTATION AND HANDLING

Crude oil and petroleum products are transported by pipelines, tankers, barges, highway tank trucks, and railroad tank cars. Today (excluding gathering lines), pipelines

Table 2-8. SUMMARY OF U.S. PETROLEUM REFINING INDUSTRY BY SIZE AND TYPE

Size and Type	Number of Refineries	Crude Capacity	
		Amount (Millions of bbl/ calendar day)	Percent of Total
Larger[a]			
Major companies[b]	83	12,354	76.28
Independents	30	1,770	10.93
Total	113	14,124	87.21
Small[c]			
Major companies	20	413	2.55
Independents	146	1,658	10,24
Total	166	2,071	12.79
Total			
Major companies	103	12,767	78.83
Independents	176	3,428	21.17
Total	279	16,195	100.00

[a]Crude capacity greater than 40,000 bbl/calendar day.

[b]Crude capacity greater than 1 percent of total industry crude capacity.

[c]Crude capacity of 40,000 bbl/calendar day or less.

Source: Tetra Tech, Inc., "Overview of the Refining Industry As It Relates to the Utilization of Low-Gravity, High-Sulfur Crude Oil and the Production of Additive Free High Octane Gasoline," TT-A-6063-78-390, December 1978.

account for 47 percent of the crude oil and product transportation, tank trucks for 29 percent, water transport for 22 percent, and rail for about 1 percent.[32]

Pipelines carry about 835 million metric tons of crude oil and products annually in the United States. Most crude oil is carried from producing wells to field storage tanks by gathering lines, which connect the tanks to trunk pipelines (long distance arteries), and usually end at a refinery or terminal. Pipelines also transport oil products from the refinery to consumer centers. A vast network of more than 356,000 km of crude oil and petroleum product pipelines now serves the 50 states and the District of Columbia.[32] Modern pipelines vary in diameter from small 5 cm lines to large 122 cm trunk lines. Pipelines have become one of the most economical means of transporting petroleum and petroleum products, costing a little more than one cent to ship a gallon of oil by large diameter pipeline from Texas to New York. Pumps move the oil through pipelines at a speed of 3 to 5 km/hour. The nearly 1,280 km crude oil pipeline from the Prudhoe Bay field on Alaska's North Slope to Port Valdez cost about $7.7 billion.[2,32] The 122 cm system is designed to move an ultimate 2 million bbl/day of crude to Valdez for shipment via tankers to the contiguous United States.[2]

Tank trucks are a major means of transporting oil products from bulk plants to consumers. At one point or another, between the refinery and its final destination, probably every oil product is carried by tank truck. Today, about 158,000 tank trucks operate in the United States, supplying more than 13 million households with more than 23 billion gal. of heating oil a year.[32] In 1976, tank trucks supplied 186,000 service stations and other outlets across the United States with almost 107 billion gal. of gasoline.[32]

Where pipelines end at waterside terminals, crude oil is transferred to tankers or barges for the second phase of its journey to refineries. The largest modern tankers are more than 396 m in overall length, with capacities of 1.75 to 3.50 million bbl of petroleum.[32] Most of the American tanker fleet operates in coastal and intercoastal trade waters. The most frequent run is between the Gulf Coast producing areas and the Atlantic seaboard, because eastern refineries depend primarily on tankers for their supplies. Most of the crude and heavy fuel oil supply to East Coast refineries is imported by tanker, primarily from points in South America and the Middle East. Modern barges are capable of hauling an average of 15,000 bbl of oil. Large seagoing barges have capacities of as much as 250,000 bbl.[32] Smaller tankers and barges are used extensively on lakes, rivers, and inland waterways.

Table 2-9. OWNERSHIP AND CAPACITIES OF LARGE PETROLEUM REFINERIES, 1977[a]

Company	Number of Refineries	Crude Capacity	
		Amount (Thousands of bbl/ calendar day)	Percent of Total[b]
Exxon	5	1,578	9.74
Chevron	7	1,383	8.54
Shell	6	1,102	6.80
Amoco	7	1,087	6.71
Texaco	9	1,040	6.42
Mobil	7	892	5.51
Gulf	6	883	5.45
Arco	3	613	3.79
Marathon	4	527	3.25
Sun Oil	5	485	2.99
Union	3	379	2.34
Ashland	4	331	2.04
Phillips	3	294	1.82
Standard of Ohio	2	288	1.78
Cities Service	1	268	1.66
Conoco	3	262	1.62
Getty	2	221	1.37
Champlin	2	200	1.24
Coastal States	1	185	1.14
Tosco	2	172	1.06
BP	1	164	1.01
Koch	1	127	0.78
Energy Coop	1	126	0.78
Clark	2	125	0.77
Southwestern	1	120	0.74
Rodeo	1	111	0.69
AM Petrofina	1	110	0.68
Crown Central	1	100	0.62
All others	22	951	5.87
Total	113	14,124	

[a]Crude capacity greater than 40,000 bbl/calendar day.

[b]U.S. total refining crude capacity is 16,195,755 bbl.

Source: Tetra Tech, Inc., "Overview of the Refining Industry As It Relates to the Utilization of Low-Gravity, High-Sulfur Crude Oil and the Production of Additive Free High Octane Gasoline," TT-A-6063-78-390, December 1978.

Railroad tank cars carry a smaller volume of oil than other modes of petroleum transportation. These tank cars range in carrying capacity from about 100 to 150 bbl/ tank car.[23]

Transporting petroleum products from the refinery to resalers and consumers most frequently involves the use of intermediate storage facilities (terminals and bulk plants). Petroleum terminals are large distribution centers. Storage facilities at terminals vary depending upon how they receive their products, the market area served, and the number of days of storage needed. Bulk plants are smaller and receive shipments by truck transport or rail, either from refineries or terminals.

ENVIRONMENTAL ISSUES

Environmental quality is a major concern in the development of the petroleum resource, but many potential problems can be prevented. For example, during geophysical exploration, vibratory or percussion devices are now used to provide accurate seismic information, reducing the number of holes that must be drilled and the use of explosives, minimizing environmental damage. In water, these devices send out pulses in the form of electrical discharges or contained explosions of propane gas or air, causing no harm to marine animal life. There is little chance of environmental pollution from exploratory operations, prior to actual drilling in the earth.[32]

Oil well blowouts, almost a trademark of early days in the industry, rarely occur because of advances in petroleum technology. The exact magnitude of pressures that will be encountered in the drilling of a well cannot always be predicted; it is not uncommon to encounter pressures greater than those imposed by the drilling fluid, resulting in formation fluids flowing into the borehole and eventually to the surface. This effect is called a blowout.[14] Weak casings on the drilling rig can also cause blowouts. A blowout preventer is used to prevent the escape of oil, water, or gas when a pressurized pocket is penetrated by a drill.

In the early days of oil production, little was known about the natural phenomena that forces oil to the surface. Wells were drilled side by side, and the natural underground pressure quickly dissipated. No control devices were available to prevent wasteful gushers. Natural gas was not marketable at that time, and was considered a nuisance rather than an asset. Consequently, much of the gas was burned off. Natural gas is no longer burned off, nor are wells drilled side by side to relieve the natural underground pressure. Wells are carefully spaced far apart and production is controlled to conserve reservoir energy for maximum recovery before pumps are used.[32] The industry also has improved oil field equipment design including oil-water separators and remote emergency equipment.

Under current practice, when an oil or gas reservoir is depleted, the site is cleaned up and the well abandoned. The hole is plugged with cement to protect the underground strata, prevent any flow or leakage at the surface that could pollute surrounding land areas, and protect water zones. Effluents in oil producing operations can be a major environmental problem. The principal effluent is salt water often found underground with crude oil. If released during drilling operation (for example, in a blowout), salt water could contaminate freshwater sources and land. Producing oil fields are equipped with saltwater disposal systems to protect fresh water and land from contamination.[32]

Searching for oil in marine environments and shipping oil by tanker involve the risk of oil spills. Ocean-going tankers transport nearly half the oil the United States uses. Oil pollution at sea results from discharges of bilge and waste spills from tanker accidents, and discharges of dirty water from tanker washings.[32] Over four-fifths of the world's tankers no longer discharge dirty water at sea, and new techniques have been developed for use at sea and on beaches for cleaning up oil spills.

Utilization of enhanced oil recovery techniques may have undesirable effects in terms of waste and pollutants. During transportation, storage, and field operations chemicals can be leaked or spilled. Moreover, the water solutions or solvents used for injection can lead to either underground contamination of aquifers or discharge of pollutants to surface water. In-situ combustion causes primarily air pollution discharges from the escape of H_2S and other gases. Steam injection, in addition to the potential for aquifer and surface water contamination, may also cause subsidence and excessive SO_2 emissions from the on-site steam boiler.

Pollution control measures for enhanced oil recovery techniques will, in general, follow those for industries with similar problems. Control of leaks and spills of chemicals during transportation and storage can be achieved through techniques specified for transportation of all chemicals. Diking techniques can contain leaks and spills during storage, treatment/disposal facilities can be developed for contaminated materials, and the effects of catastrophic tank failures can be reduced by the provision of emergency ponds.

The potential for contamination of aquifers and surface water during enhanced recovery of oil is similar to that during primary recovery; contamination potential must be analyzed from a site-specific viewpoint. In many oil fields, brines and contaminated water streams can be disposed of by underground injection, without contaminating freshwater aquifers.

Three-fourths of America's crude oil and almost one-third of the refinery products move around the country in pipelines, which have minor amounts of leakage.[32] Safety measures that help prevent pollution include regular pipeline inspections, ultrasonic leak detectors, corrosion preventives, and automatic shutdown techniques that go into operation in case of a leak.

Refiners in the past contributed to the pollution of air and water. Refinery wastewater streams contain traces of oil, suspended solids, and other chemicals. If not properly treated, these wastes pollute rivers. In refinery operations, major emissions include H_2S and sulfur oxides.[32] Today, noxious emissions of fumes and odors have been eliminated to a great extent. Sulfur-containing gases in refinery operations are removed and converted to solid sulfur, which can be sold commercially. A refinery uses great quantities of water for cooling and processing, usually from a river, and that water is now purified to remove oil and other wastes. Refinery wastewater streams are treated to meet local regulations before being discharged into sewers, rivers, or bays. Air is replacing water as a coolant in some systems, with a resultant decrease in thermal pollution.[32] Additionally, refineries have taken steps to reduce the light and noise of refining by shielded, smokeless flares and by equipment silencers.

PETROLEUM PRICING AND ALLOCATION

Domestic Petroleum

Since August 1971, the United States government has maintained four types of controls on domestic petroleum:

- Prices of crude oil.
- Prices of products produced from crude.
- Allocations of crude and products from sellers to buyers.
- Transfer payments, or entitlements, from some refiners to other refiners.

The basic purpose of the controls is to reduce the inflationary effects of large increases in energy prices, yet maintain equity among various sectors of the industry.

The controls are administered principally by DOE. Current major legislation mandating the controls includes the Energy Policy and Conservation Act (EPCA), passed by Congress on 22 December 1975, and the Energy Conservation and Production Act (ECPA), signed on 14 August 1976. A major feature of EPCA is that it set a maximum average, or composite, wellhead price for domestically produced crude oil effective 1 February 1976. (This was effectively a "rollback" in the price of crude oil.) EPCA also provides for an increase of 10 percent per year. Crude oil price controls under the EPCA remain in effect at least until April 1979.

Crude Oil Price Controls

Wellhead prices of domestic crude oil are established based on initial production date of the well, geographic area, oil quality, supply-demand relationships, competitive pricing

with other oil, and related factors.[33] Basically, a three level, or three tier, system of price controls was instituted:

- The lower tier and price is for crude oil produced from wells that began production prior to 1973. (Only old oil was controlled before February 1976.)
- The middle level, or upper tier, applies to production from wells that started producing in 1973 or later plus incremental production that exceeds a certain base-production level.
- The highest level and price is for imported and stripper well oil.

The price of old, lower tier oil was established by starting from the price of domestic crude in the base period of 15 May 1973. The allowable price per barrel of a particular crude oil as of February 1976 was the 15 May 1973 posted price plus $1.35. Upper tier oil sells at a substantially higher price than old oil, but below the international (import) price. In February 1976, the price of new oil was established by subtracting $1.32/bbl from the posted price for that same crude oil which existed on 30 September 1975. Imported oil is, of course, not controlled. Stripper well oil comes from domestic wells producing 10 bbl/day or less, and can be sold at the import price. (DOE removed price controls from stripper oil in an effort to encourage small producers.)

A major issue in the control program is the criteria used to classify oil as new oil and therefore make it eligible for the upper tier price. The regulations have changed many times, but the underlying principle remains the same: for a given oil well, the level of production in a selected base period is classified by DOE as "old" oil. It is "old" in the sense that it is equivalent to the volume that was being produced in a previous time period. The "old" oil gets the lower tier price.

While the prices of old oil and new oil are established by the general procedures described above, the EPCA also required that the price of all domestic oil must average $7.66/bbl in February 1976. This composite price was established on the assumption that approximately 60 percent of oil domestically produced would be old oil at an average price of $5.25/bbl, and 40 percent would be new oil at an average price of $11.28/bbl.

Congress recognized that adjustments in the price levels would be necessary after February 1976. It was thought that unless prices were allowed to rise in step with overall inflation, incentives for domestic production would decline, and the United States would import more foreign oil, thus exacerbating both the rate of inflation and the deteriorating balance of payments. Under EPCA, the $7.66/bbl composite price was allowed to rise 10 percent per year to account for inflation and encourage domestic production.

Table 2-10 shows the domestic crude petroleum prices at the wellhead for 1976 and 1977. Because the actual average price in February 1976 exceeded $7.66/bbl, the government, in June 1976, froze domestic crude prices through early 1977. In addition, DOE chose for many months to increase crude prices only at the rate of inflation, or about half the rate of increase that would have been allowed in late 1977 and early 1978.[2] In September 1978, the EPCA composite price for domestic oil was $9.73/bbl.[34] Assuming half of the U.S. crude oil supply was imported at a deliverable price of $14.00/bbl, the actual price for all crude oil used in the United States in September 1978 averaged about $11.85/bbl.

Table 2-10. CRUDE OIL PRICES, BY MONTH

Month	Price		
	Lower-Tier Oil[a]	Upper-Tier Oil[b]	Domestic Average[c]
1976			
February	5.05	11.47	7.87
March	5.07	11.39	7.79
April	5.07	11.52	7.86
May	5.13	11.55	7.89
June	5.15	11.60	7.99
July	5.19	11.59	8.04
August	5.18	11.62	8.03
September	5.17	11.65	8.19
October	5.15	11.62	8.23
November	5.17	11.2	8.40
December	5.17	11.64	8.40
1977			
January	5.17	11.44	8.28
February	5.18	11.39	8.33
March	5.15	11.03	8.19
April	5.15	10.97	8.14
May	5.18	10.98	8.23
June	5.16	10.92	8.17
July	5.16	10.99	8.21
August	5.18	10.93	8.25
September	5.20	11.20	8.26
October	5.23	11.42	8.36
November	5.24	11.63	8.35
December	5.25	11.76	8.40

[a]From properties that began producing before 1973.

[b]From properties that began producing since 1973 from older properties exceeding a certain base-production level.

[c]Beginning September 1976, an imputed domestic average was calculated where the average price is used to establish ceiling prices for domestic crude oil in accordance with the provisions of ECPA. It is calculated as the weighted average of lower tier, upper tier, and an imputed stripper crude oil price.

Sources: *International Petroleum Encyclopedia* (Tulsa, OK: Petroleum Publishing Company, 1978); and U.S. Department of Energy, Energy Information Administration, "First Purchases Crude Oil Price Analysis," 8 January 1979.

Other factors affect the price for crude oil. Particularly desirable types (light and sweet) of both old and new oil sell for more than the average price; heavy or sulfurous crude sells for less. Production from a given well tends to decline over time; that is, it may fall below the production level in the base period. This decline in production can sometimes be prevented or slowed down by various enhanced oil recovery techniques. DOE provides the owners of oil wells with an incentive to undertake such techniques by allowing increased production over the level produced in the base period to sell at the upper tier price. However, DOE regulates the prices for the two tiers to ensure that the composite average price does not exceed the maximum established by EPCA.

Petroleum Product Price Controls

The second part of the U.S. government control program covers the prices of products refined from petroleum. Crude oil is refined into gasoline, home heating oil, diesel oil, naphtha, asphalt, and numerous other products. The prices of all refined products were controlled until the spring of 1976. EPCA permits products to be exempted from controls on an individual basis, as the government decides the controls are no longer necessary. Presently, price controls exist for products such as gasoline, propane, butane, and jet fuel for commercial aircraft. Price controls for other products may be reinstituted if shortages or very large price increases for those products occur.

The price of controlled products equals the May 1973 price of the product plus certain cost increases that have occurred since that time. In general, increases in the cost of crude oil or other raw materials, labor costs, and other costs associated with producing the product may be added to the May 1973 price of controlled products; increases in taxes and research and development costs are not allowed to be passed through to the product selling price. Currently, there is no plan to allow all associated cost increases to be passed through to the selling price of controlled products.[35]

Crude Oil and Product Allocation

In addition to price controls, the government regulates the quantities of crude oil and controlled products in the form of supplier-purchaser relationships. The details of the rules governing crude oil and products differ; however, the general principles are the same. A base period supplier-purchaser relationship exists if, in December 1973, a given buyer was purchasing from a given seller. Sellers are required to offer to sell an amount equal to the base period (December 1973) quantity to the buyer that constitutes the supplier-purchaser relationship, even if the seller does not wish to do so. This supplier-purchaser relationship is intended to ensure that, under normal supply conditions, a purchaser has access to that quantity available to him in December 1973. During an embargo or other abnormal supply condition, when total December 1973 quantities may not be available, sellers are required to prorate available crude oil and controlled products to buyers that constitute their supplier-purchaser relationships.

The first sale from a new oil-producing property may be made to any purchaser. Once that first sale is made, the supplier-purchaser relationship is binding; DOE regulations stipulate certain conditions that may terminate the relationship, however. Even if one relationship is terminated, another is formed when the oil is sold to another purchaser.

DOE may assign a supplier to a buyer, including, but not limited to, a new firm that has difficulty in purchasing needed crude oil and products. Such assignments are not based on historic supplier-purchaser relationships. In one exercise of this authority, the government created the crude oil buy-sell program. In the buy-sell program, several large refiners are required to sell crude oil to small refiners and other specified purchasers.[35]

Entitlements Program

The entitlements program is an equity program that attempts to equalize the cost of crude oil for all refiners. The crude oil price controls result in different prices for crude oil. Refiners that have access to lower tier (lower priced) crude oil have a cost advantage over firms dependent on upper tier or imported oil. Product price controls require firms with access to lower cost crude oil to price their products at a lower level than products from refiners dependent on more expensive crude oil. The government believed that consumers would favor those firms selling at lower prices over those firms required to sell at higher prices. The result would be the creation of inequities owing to the control program—not a desirable effect of government policy.

The entitlements program was instituted to prevent inequities resulting from the control program. Basically, refiners with access to unusually large amounts of cheaper, lower tier oil are required to pay a subsidy to refiners dependent on more expensive crude oil. The actual exchange of funds occurs when refiners with large amounts of lower tier oil buy entitlements from firms with less than the average amount of cheaper crude. The firm buying the entitlement is then "entitled" to refine its excess (above average) lower tier oil. An example of this process is as follows. If the average amount of domestic old oil is 60 percent, entitlements are issued on the basis that all refiners should reflect this 60/40 in the crude oil costs. If one refiner has more than 60 percent old oil and another has less than 60

percent, then the firm having the higher ratio must buy entitlements from the refiner having less than 60 percent. These payments—one buying entitlements from the other—would have the desired effect of approximately equalizing the crude oil costs to all firms.

The price of an entitlement is approximately the average cost per barrel of imported oil less the average cost per barrel of old domestic oil. These costs are reported by refiners to DOE, which computes the monthly ratio of old oil to new oil, calculates the entitlement price, and determines how many entitlements each firm must buy or sell. The actual result for any month depends on factors such as the amount of imported and stripper well oil. Also, the size of the refinery is used in calculating the entitlement obligation (how many entitlements it must buy or sell) of each individual refiner. Under DOE's formula, additional entitlements are issued to small refiners whose output is less than 175,000 bbl/day, reducing the crude oil cost of small relative to large refiners.[35]

International Oil

The international price of crude oil is set by a cartel composed of the member nations of OPEC, and is based on the official selling price of Saudi Arabian light, or marker crude. The delivered price to a buyer of crude oil will vary according to quality differences relative to marker crude and transportation costs. Table 2-11 shows the official OPEC selling price of marker crude. Following the 1973-74 embargo of petroleum and petroleum products by the Arab nations, OPEC more than tripled the price of marker crude—initiating not only the "energy crisis," but the largest international transfer of wealth in history.

Table 2-11. SELLING PRICE OF ARABIAN LIGHT

Period	Direct Sales Price[a] (Dollars/bbl)
May 1973—Base price	2.55
September 1973-15 October 1973	2.86
16 October 1973-31 October 1973	4.76
November 1973	4.81
December 1973	4.68
January-May 1974	10.95
June-September 1974	11.05
October 1974	10.84
November 1974-September 1975	10.46
October 1975-December 1976	11.51
January-June 1978	12.09
July 1977-December 1978	12.70
January-March 1979	13.34
April-June 1979	13.84
July-September 1979	14.16
October-December 1979	14.54

[a]FOB prices set by the government for direct sales and, in most cases, for the producing company buy-back oil.

Sources: *Petroleum Intelligence Weekly*, Vol. XVII, No. 52, December 1978; Parra, Ramos, and Rarra, *International Crude Oil and Product Prices*, in cooperation with Middle East Economic Survey, 15 October 1975; and Central Intelligence Agency, 1978.

The January 1977 price of $12.09/bbl for marker crude resulted from a lack of agreement among OPEC members at their December 1976 meeting in Doha, Qatar. The disagreement resulted in a two-tier price structure. The United Arab Emirates (U.A.E.) and Saudi Arabia (lower-tier countries) chose to raise the price of marker crude about 5 percent; the remaining 11 OPEC members opted for price increases of about 10 percent as of 1 January 1977, to be followed by another 5 percent increase at mid-year. After about 6 months of confusion, OPEC members reached a compromise to be effective 1 July 1977. Saudi Arabia and the U.A.E. increased their prices 5 percent; the re-

maining OPEC countries agreed to forgo their scheduled 5 percent mid-year increase. The net effect was a 10 percent increase for OPEC oil during 1977.[2]

OPEC ministers avoided another two-tier price structure when they failed to agree on an increase for 1978 at their meeting in December 1977. The OPEC ministers heeded the advice of Saudi Arabia, the U.A.E., Iran, Qatar, and Kuwait, who insisted on a price freeze for at least the first half of 1978. The freeze remained throughout 1978 at $12.70/bbl for Arabian light.[2] In late 1978, OPEC increased the official selling price of marker crude by 14.49 percent. The international price of marker crude will increase from $12.70/bbl to $14.54/bbl during 1979.

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3. NATURAL GAS

Natural gas, which supplies about 18 percent of the worldwide demand for energy,[1] has been used commercially as a fuel for over 150 years in the United States and for centuries in China. Its production and distribution are an important segment of the U.S. economy. The United States produces about 38 percent of the world's natural gas, but U.S. reserves represent only 8 percent of the world's total.[1,2] Domestic consumption of natural gas, which accounts for 27 percent of the total U.S. energy consumption (Table 3-1),[1] grew fourfold from 1950 to 1970, exceeding that of any other fuel. This increase occurred in part because natural gas was the most inexpensive domestic fuel and also because natural gas is a major petrochemical feedstock. In addition, a major network of long-distance interstate pipelines was built, linking gas-producing regions to major consuming areas.

Table 3-1. NATURAL GAS FACTS

Energy content	1,000 Btu/scf
Proved U.S. reserves, 1977	208.9 tcf
U.S. resources	700-1,035 tcf of potential remaining recoverable discoverable natural gas resources.
U.S. production, 1977	19.45 tcf
Imports, 1977	1.009 tcf
U.S. consumption, 1977	19.6 tcf
Contribution to demand	Natural gas supplied 27 percent of the 1977 U.S. energy demand.

Sources: National Petroleum Council, "Domestic Oil and Gas Availability," *U.S. Energy Outlook,* December 1972; American Gas Association, October 1978; U.S. Geological Survey, "Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States," Circular 725, 1975; U.S. Department of Energy, Energy Information Administration, October 1978; U.S. Department of the Interior, Bureau of Mines, 1978; and American Petroleum Institute, American Gas Association, and the Canadian Petroleum Association, "Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1977," Vol. 32, 1978.

NATURAL GAS CHARACTERISTICS

Natural gas is found in natural underground reservoirs generally composed of porous sedimentary rocks that provide space and entrapping conditions to terminate migration and cause the accumulation of hydrocarbon fluids and gases. In the reservoir, natural gas occurs in the gaseous phase under pressure or in solution with crude oil. Natural gas and natural gas liquids are not distinguishable as separate substances under reservoir conditions. Based on the type of occurrence in the reservoir, the American Gas Association classifies natural gas in two categories: nonassociated gas, which is free natural gas not in contact with crude oil in the reservoir, and associated-dissolved gas, which is the combined volume of natural gas that occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with the crude oil (dissolved). Associated gas commonly is referred to as gas-cap gas.[3,4]

In the early days of the petroleum industry, natural gas and crude oil were characterized as separate and distinct substances because the shallow wells then in production either delivered natural gas or produced oil.[5] As drilling and discovery depths for oil and gas increased, natural gas usually occurred associated with the crude oil, and hydrocarbon liquids were found to condense from natural gases. Since temperatures and pressures in the

reservoir usually are high compared to atmospheric conditions, gas expansion and cooling causes liquid hydrocarbons to condense from gas brought to the surface. Natural gas liquids are recovered at the surface by separation from produced natural gas using processes such as condensation and absorption in field separators, gas processing plants, and cycling facilities. Thus, the availability of natural gas liquids (natural gasolines, condensate, and liquefied petroleum gases) depends directly on the rate of production of gas from crude oil or natural gas reservoirs.

Methane is the primary constituent of natural gas. Other hydrocarbons—ethane, propane, and butanes as well as heavier paraffins—are present in minor amounts. Noncombustible components include nitrogen, carbon dioxide, hydrogen sulfide, helium, and water vapor. Natural gas accompanying petroleum—wet gas—always contains appreciable quantities of ethane, propane, and butane as well as some pentane and hexane vapors. Dry gas contains little of these higher hydrocarbons. Liquefied petroleum gas (LPG) is composed primarily of propane, propylene, butanes and/or butylenes.

The exact composition of natural gas varies with locality. The degree of compositional variability of natural gases in different petroleum producing regions is illustrated in Table 3-2, which shows the chemical composition of natural gas from six fields in the United States and Canada, and Table 3-3, which indicates the chemical character of natural gas condensate from six U.S. fields.

The properties of natural gas vary as the proportions of the constituents vary. The heating value of natural gas varies considerably with composition, but is usually about 1,000 Btu/per standard cubic foot (scf) unless nitrogen or carbon dioxide are important components of the gas. The burning velocity of natural gas is not greatly affected by the proportions of inert gases in the mixture or by the proportions of paraffins up to butane.[6] The presence of condensable or corrosive constituents affects the operation of gas transmission and distribution systems. The heavier hydrocarbons and water vapor in natural gas are condensable constituents; hydrogen sulfide, carbon dioxide, and oxygen are the main corrosive constituents.[6]

GAS AVAILABILITY AND UTILIZATION

World resources of ultimately recoverable natural gas are estimated to range from 8,164 trillion cubic feet (tcf) to 10,513 tcf.[7-9] Of this, about 2,520 tcf are proved, or measured, reserves.[1,2] The proved reserve is the current estimated quantity of natural gas thought to be recoverable under existing economic and operating conditions.[3,10] Gas reserves are determined by geological and engineering analyses of reservoir data, including structural interpretation, well tests, core analysis, pressure-production data, gas analysis, and other types of evaluations available at the time the estimate is made. Recoveries of gas are estimated on the basis of formation evaluation of the reservoir rock, the producing mechanism (driving force) of the reservoir, and pressure-production performance.[3]

The distribution of world proved reserves is shown in Figure 3-1; only 8 percent (about 209 tcf) is located in the United States, while over 36 percent is located in the USSR. Of the

Table 3-2. COMPOSITION OF NATURAL GAS, BY FIELD

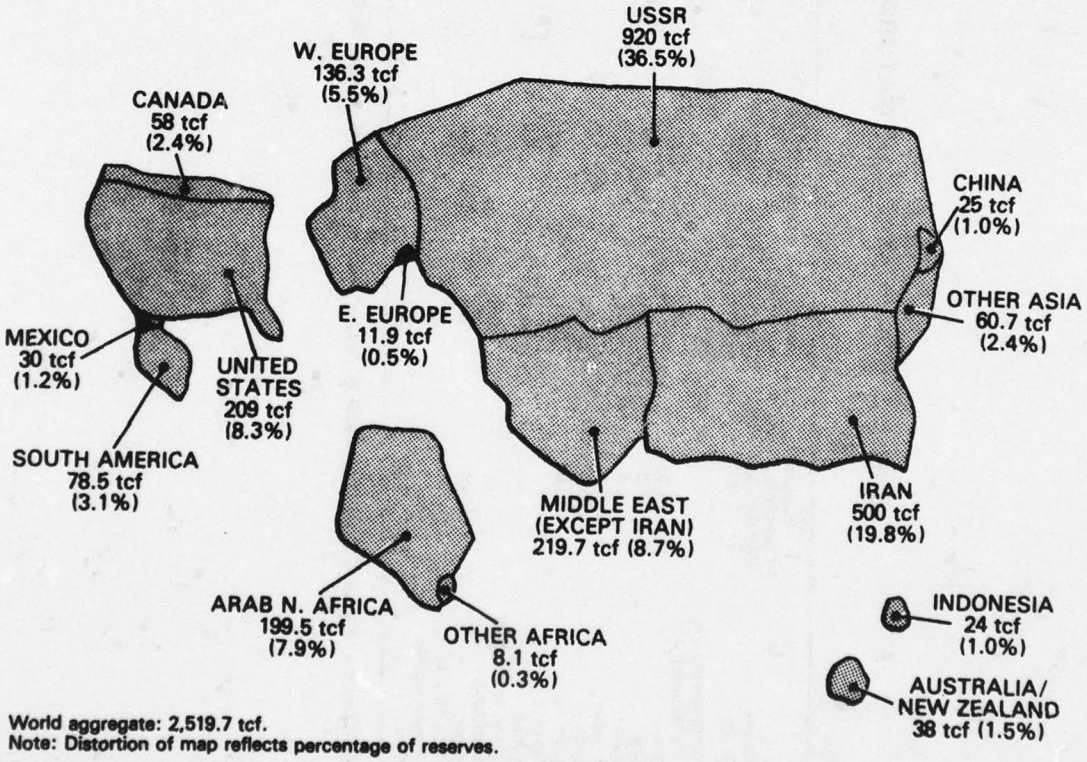
Field State Formation Depth (ft)	Hugoton *Oklahoma, Texas* Permian Dolomite 3,000	Austin *Michigan* Stray Sand 1,200	Leduc Gas Cap D-3 *Alberta* Devonian 5,000	Viking, Kinsella *Alberta* Cretaceous Sand –	West Cameron, Blk 149 *Louisiana (Gulf)* Miocene Sand 7,150	Deep Lake *Louisiana* Miocene Sand 6,950
Gas components (percent by volume):						
Methane	71.51	79.74	72.88	88.76	96.65	98.50
Ethane	7.0	9.1	9.97	4.76	2.05	0.87
Propane	4.4	2.8	5.09	2.67	0.47	0.17
Isobutane	0.29	0.1	0.72	0.42	0.08	0.04
n-Butane	0.70	0.4	1.76	0.21	0.09	0.02
Isopentane	0.02	0.1	0.99	0.38	0.03	0.01
n-Pentane	–				0.02	0.01
Hexanes	–	0.05	0.46	0.30	0.31	0.08
Heptane and higher homologs	–	0.01	–	–	–	–
Nitrogen	15.5	7.3	7.41	0.24	–	–
Carbon dioxide	–	–	0.72	2.26	0.30	0.30
Hydrogen sulfide	–	–	–	–	–	–
Helium	0.58	0.4	–	–	–	–

Source: Donald L. Katz and others, *Handbook of Natural Gas Engineering* (New York: McGraw-Hill Book Company, 1959).

Table 3-3. COMPOSITION OF CONDENSATE WELL FLUIDS, BY FIELD

Field	Erath	Erath	Paloma	Chocolate Bayou	North Pettus	Frio Formation
State	Louisiana	Louisiana	California	Texas	Texas	Texas
Reservoir depth (ft)	10,150	11,560	10,000	9,675	6,950	6,760
Pressure (psia)	4,700	5,431	4,400	4,465	3,056	3,836
Temperature (°F)	205	212	256	235	221	201
Gas condensate components (percent by volume):						
Methane	80.95	91.32	74.55	85.11	86.27	90.74
Ethane	4.47	3.42	8.28	5.04	6.30	4.35
Propane	3.13	1.34	4.74	2.44	2.31	1.69
Isobutane	1.55	0.48	0.89	0.67	0.32	0.36
n-Butane	1.77	0.41	0.73	0.73	0.62	0.54
Isopentane	1.49	0.42	0.75	0.32	0.35	0.20
n-Pentane			0.63	0.38	0.25	0.21
Hexanes	1.3	0.36	1.25	0.61	0.29	0.42
Heptane and higher homologs	5.62	1.96	6.30	2.94	1.08	1.49
Nitrogen	—	—	—	—	0.24	—
Carbon dioxide	—	0.31	0.68	1.76	1.97	—

Source: Donald L. Katz and others, *Handbook of Natural Gas Engineering* (New York: McGraw-Hill Book Company, 1959).



World aggregate: 2,519.7 tcf.
Note: Distortion of map reflects percentage of reserves.

Sources: *International Petroleum Encyclopedia, 1978* (Tulsa, OK: Petroleum Publishing Company, 1978) and British Petroleum Company, "BP Statistical Review of the World Oil Industry, 1977."

Figure 3-1. WORLD PROVED NATURAL GAS RESERVES

proved U.S. gas reserves, 68 percent is nonassociated gas, 30 percent is associated-dissolved gas, and 2 percent is contained in underground storage reservoirs.[3] Table 3-4 shows the distribution of U.S. proved reserves by state.

Table 3-5 shows the distribution of world natural gas production. The United States and USSR are the prominent producers, accounting for 60 percent of total production. Within the United States, Texas, Louisiana, Oklahoma, and New Mexico have been the large producers of natural gas; newly developed fields in Alaska are also significant gas producers. Natural gas production in the United States peaked at 22.2 tcf in 1973 and has been

Table 3-4. ESTIMATED TOTAL PROVED RESERVES OF NATURAL GAS IN THE UNITED STATES AS OF 31 DECEMBER 1977[a] (Billions of cubic feet)

State	Nonassociated	Associated-Dissolved	Underground Storage[b]	Total
Alabama	717	29	0	746
Alaska	5,492	26,341	0	31,833
Arkansas	1,506	149	25	1,680
California[c]	1,961	2,841	397	5,198
Colorado	1,754	235	37	2,026
Florida	0	215	0	215
Illinois	1	1	416	418
Indiana	1	<1	52	53
Kansas	11,670	144	113	11,926
Kentucky	567	42	136	745
Louisiana[c,d]	42,969	9,410	307	52,686
Michigan	614	588	589	1,791
Mississippi	1,126	95	86	1,307
Montana	816	67	161	1,044
Nebraska	6	15	48	68
New Mexico	9,450	2,452	30	11,931
New York	138	<1	109	247
North Dakota	5	387	0	392
Ohio	944	149	366	1,459
Oklahoma	9,171	2,293	248	11,712
Pennsylvania	1,317	11	556	1,885
Texas[c]	46,465	15,476	217	62,158
Utah	405	342	2	749
Virginia	69	0	0	69
West Virginia	1,952	49	375	2,376
Wyoming	3,324	585	54	3,963
Miscellaneous[e]	23	3	174	199
Total	142,460	61,918	4,500	208,878

[a]Totals may not add due to rounding.

[b]Proved recoverable gas contained in underground storage reservoirs, including native and net injected gas.

[c]Includes offshore reserves.

[d]Reported quantities include reserves estimated to be recoverable from some reservoirs considered natural gas bearing based on electrical logs, core data, and other available engineering and geological data.

[e]Includes Arizona, Iowa, Maryland, Minnesota, Missouri, South Dakota, Tennessee and Washington.

Source: American Petroleum Institute, American Gas Association, and the Canadian Petroleum Association, "Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1977," Vol. 32, 1978.

Table 3-5. DISTRIBUTION OF WORLD NATURAL GAS PRODUCTION, 1977

Area/ Country	Production (tcf)	Percent of World Total
North America	24.38	45.3
United States	20.34[a]	37.7
Canada	3.30	6.1
Mexico	0.75	1.4
South America and Caribbean	1.37	2.5
Middle East	2.79	5.2
Iran	1.76	3.3
Other	1.03	1.9
Europe	6.29	11.7
Netherlands	2.93	5.4
United Kingdom	1.50	2.8
Other	1.86	3.4
Africa	1.78	3.3
Asia—Pacific	1.27	2.4
Communist countries	16.00	29.7
USSR	12.40	23.0
Other	3.60	6.7
World total	53.88	100.0

[a]Includes natural gas liquids.

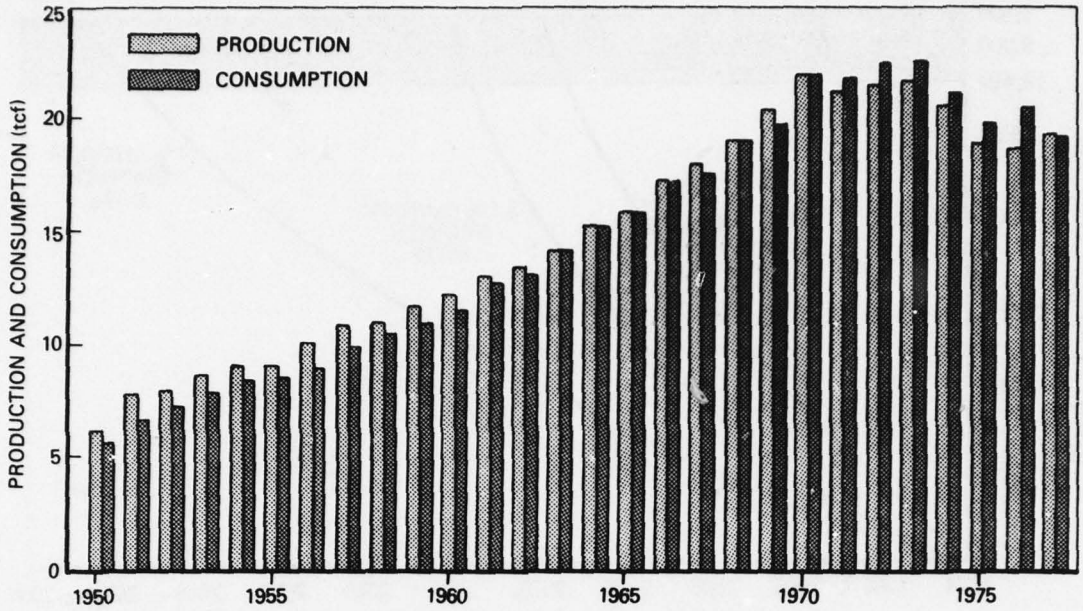
Source: *International Petroleum Encyclopedia, 1978* (Tulsa, OK: Petroleum Publishing Company, 1978).

declining since then at a rate of about 3.1 percent per year.[11] The finding rate (amount of gas discovered versus the number of meters drilled) has declined even faster. Figure 3-2 shows U.S. gas production trends since 1950; consumption trends also are shown. In 1977, the United States consumed about 20 tcf of natural gas and, together with the USSR, accounted for 67 percent of total world natural gas consumption. U.S. consumption of natural gas by end use is shown in Figure 3-3.

Figure 3-4 presents three possible production and consumption scenarios that indicate theoretical gas exhaustion dates. These dates are calculated using the estimates from Table 3-5, data on natural gas resources, and simplified assumptions about production and consumption policies. The curve indicating a 3.5 percent annual growth rate represents current world gas production and consumption patterns. As shown in Figure 3-4, the world supply of natural gas could be depleted by 2022 to 2025 if consumption grows at a rate of 5 percent. If the annual growth in consumption rate were only 1 percent, exhaustion of remaining ultimately recoverable reserves would occur between 2072 and 2079.

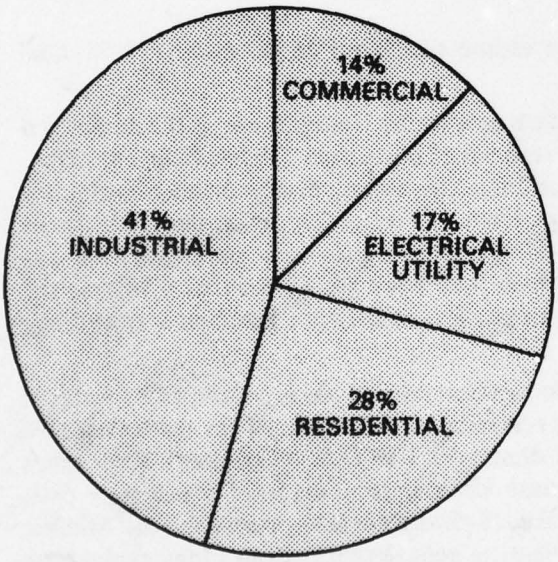
The decrease in the supply of natural gas has led to increased interest in developing unconventional sources of gas. These gas sources could provide 200 to 220 tcf of additional gas to the United States, an amount equal to the current proved U.S. reserves.[12] These unconventional sources include:

- *Geopressured aquifers.* Gas dissolved in hot water and contained in geopressured deep sands along the coast (both on and offshore) of Louisiana and Texas probably constitutes the largest quantity of methane in place in the United States. These geopressured zones of the northern Gulf of Mexico basin cover an estimated 258,990 m^2, and could contain as much as 50,000 tcf of gas. An additional 50,000 tcf may be contained in adjacent geopressured shale formations.[13] (Lower estimates have ranged from 3,000 to 23,618 tcf.[14,15])
- *Devonian shales* of the Appalachian Basin, which extends from northern New York to Alabama in an area of some 647,475 m^2. The shales, ranging in thickness from a meter to about 90 m, are estimated to contain 500 to 600 tcf of gas-in-place.[16] However, only 15 to 25 tcf may be ultimately recoverable.[17] The rocks in part of the region have been folded and faulted so intensely that few geologists consider them important sources of oil or gas, but areas such as the Appalachian Plateaus where



Source: American Petroleum Institute, American Gas Association, and Canadian Petroleum Association, "Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States as of December 31, 1977," Vol. 32, 1978.

Figure 3-2. U.S. PRODUCTION AND CONSUMPTION OF NATURAL GAS, 1950-1977

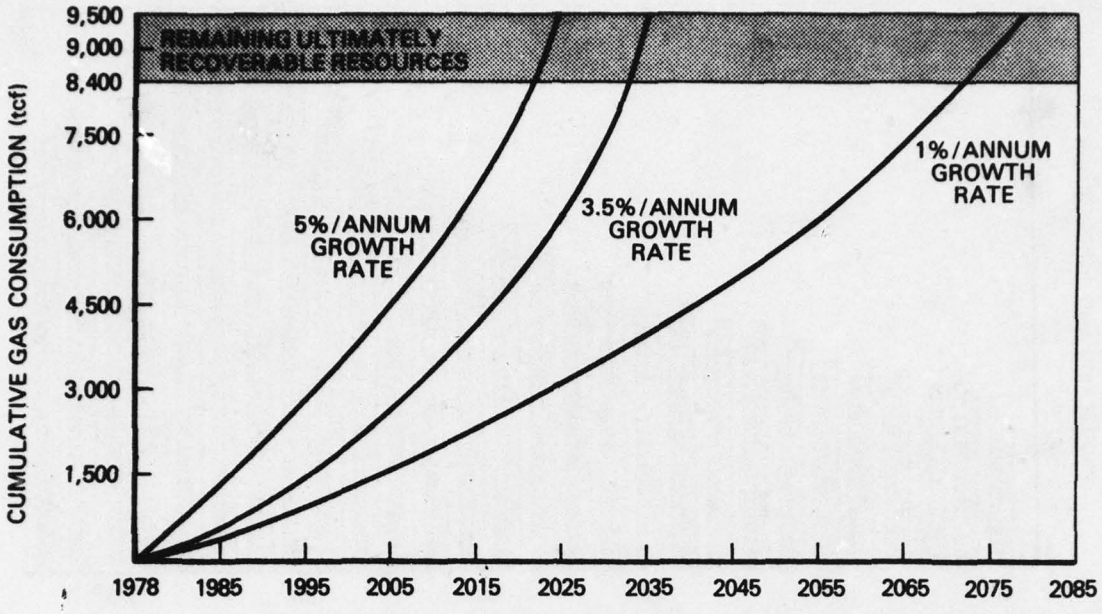


Source: U.S. Department of Energy, Energy Information Administration, April 1978.

Figure 3-3. U.S. CONSUMPTION OF NATURAL GAS BY END USE

the rocks are flat-lying or only gently folded may have considerable potential for gas production.[18]

- *Western tight sands.* Extensive deposits of natural gas exist in tightly compacted beds of sandstone in the western United States. The gas is located in consolidated sands having low permeability (0.001-1 millidarcy) and low porosity (5 to 15 percent).[19,20] The total gas-in-place is estimated at 1,200 tcf; the major deposits are found in the Mesa-Verde Formation and Fort Union area, which contain 600 tcf of gas, and the San Juan basins and Denver-Julesberg basins, which also contain 600 tcf.[20,21]
- *Coal seams.* All coal contains methane. In some places, methane is present in porous strata above or below the coal, but for the most part gas is absorbed within the coal seams, which, in turn, are



Sources: Congressional Research Service," Project Interdependence: U.S. and World Energy Outlook Through 1990," June 1977; *International Petroleum Encyclopedia, 1978* (Tulsa, OK: Petroleum Publishing Company, 1978); American Gas Association, "AGA Study Assesses World Natural Gas Supply," *The Oil and Gas Journal,* 13 February 1978; and American Gas Association, "A Comparison of U.S. and World Remaining Gas and Oil Resources," *Energy Analysis,* 19 January 1979.

Figure 3-4. WORLD NATURAL GAS EXHAUSTION

enclosed by strata of low porosity. An estimated 850 tcf of gas exists in U.S. coal seams at depths as great as 1,830 m.[19]

- *Deep basins.* One of the most productive basins in the United States is the Anadarko Basin in Oklahoma, with conventional reserves of more than 130 tcf. Below 4,570 m, the basin has 57,000 km² of sediments still virtually untouched by drilling. Estimates of unconventional reserves of gas range from 350 tcf to 700 tcf at depths between 4,570 and 12,190 m.[19] Other areas of the United States with potential deep gas reserves are the Appalachian Basin, which may have gas as deep as 9,145 m; the Arkoma Basin in Arkansas and Oklahoma; the Mississippi Embayment; and the Delaware Basin in Texas.[19]
- *Methane hydrates.* Methane hydrates form when natural gas is contacted by water at about 1,470 psi and 0°C; the process is reversible and the natural gas can be released if temperatures increase or pressures diminish. The U.S. Geological Survey has found evidence that thousands of square kilometers of hydrate layers may exist beneath the Beaufort Sea, north of Alaska. Hydrates are also present off the Atlantic coast of North and South America. Scientists believe that hydrates may explain the large amounts of methane found in hundreds of locations studied since 1968 as part of the National Science Foundation's Deep Sea Drilling Project.[19] (Many U.S. gas producers doubt that hydrates represent a significant source, but Soviet scientists estimate that 35 million tcf, a 30,000 year world supply, exists in world permafrost

regions and in deep ocean sediments.[19]) Despite the apparently vast amounts of hydrates in the earth, recovering appreciable quantities of gas from hydrates will be extremely costly. Considerable research and major advances in offshore drilling technology lie ahead before hydrates can be considered a feasible source of gas.

Another source of gas is synthetic natural gas produced by gasifying crude oil or other liquid hydrocarbons (Chapter 2), gasifying coal (Chapter 4), partial oxidation or anaerobic digestion of biomass (Chapter 12), and steam reforming or partial oxidation of hydrocarbons for hydrogen production (Chapter 14). Synthetic natural gas consists mostly of methane with small amounts of ethane and carbon dioxide present.

EXPLORATION AND DRILLING

The methods used in the exploration and drilling of gas wells are the same as those used for oil wells. Although no differences arise for drilling either type of well down to the top of the producing formation, there often are differences in well-completion methods. Once a gas well is completed, tests are made to evaluate the gas content of the field and the flow capacity of the well. Exploration and drilling methods are discussed in Chapter 2.

GAS RECOVERY

Once a gas field discovery is made by drilling one or more wells, a plan is required for developing the field and marketing the gas. Estimates of reserves of natural gas and natural gas liquids are needed as a basis for determining the market for the gas and liquid products. An adequate number of wells in the field must be planned for producing gas at required rates for the projected gas deliveries. Operation of a gas field is continued until it is depleted to the point specified by reservoir and economic conditions. In reservoirs of associated-dissolved gas, where the ultimate recovery of crude oil is affected by the production of the associated gas, gas production usually is limited by regulation or by operating practice to assure maximum recovery of the crude oil.[3]

The volumes of gas which can be recovered during the economic life of a reservoir are quite high. A greater percentage of gas in a reservoir can be recovered than is possible for crude oil because gas has a lesser tendency to wet the rock in the reservoir and remain in-place. However, a part of the original volume of gas in the reservoir cannot be recovered because of certain physical and economic constraints such as the inability to obtain gas from the heterogeneous rock formations in the reservoir, to remove gas trapped in the reservoir by the influx of water, and to produce economically when reservoir pressure becomes too low. Since production rates in reservoirs producing natural gas by gas expansion and without water drive decrease rapidly when reservoir pressure approaches atmospheric pressure, some minimum pressure usually is established below which commercial production is no longer feasible. For example, abandonment pressures may be as low as 50 psia for shallow reservoirs and as high as 500 psia or more for deep gas reservoirs. [3,22,23]

A water-drive reservoir has large quantities of salt water under pressure directly in con-

tact with the oil and gas, which provides a large additional store of energy to assist in producing oil and gas. In water-drive reservoirs, the expanding water moves into regions of lower pressure in the oil- and gas-saturated regions of the reservoir and retards the decline in pressure. Thus, oil fields of this type are the most efficient and can yield recoveries up to 50 percent of the original oil in place.

Once a gas reservoir is producing, its production rate usually is specified both for the overall average and the maximum per day. Enough wells are drilled to ensure production of the water front into the producing zone. For water-drive fields, gas flow rates generally are set to allow for a uniform advance of the water front into the producing zone. Once the water reaches a well, water may be produced together with the gas for a period of time before the well is shut down. Some of these wells may be recompleted, that is, put in production again, in another horizon if there are multiple horizons in the same reservoirs in the field. If the reservoir is producing by pressure depletion and the gas-sales contract requires a minimum pressure for delivering gas, field compressors are installed to maintain pressure as the field reaches abandonment pressure.

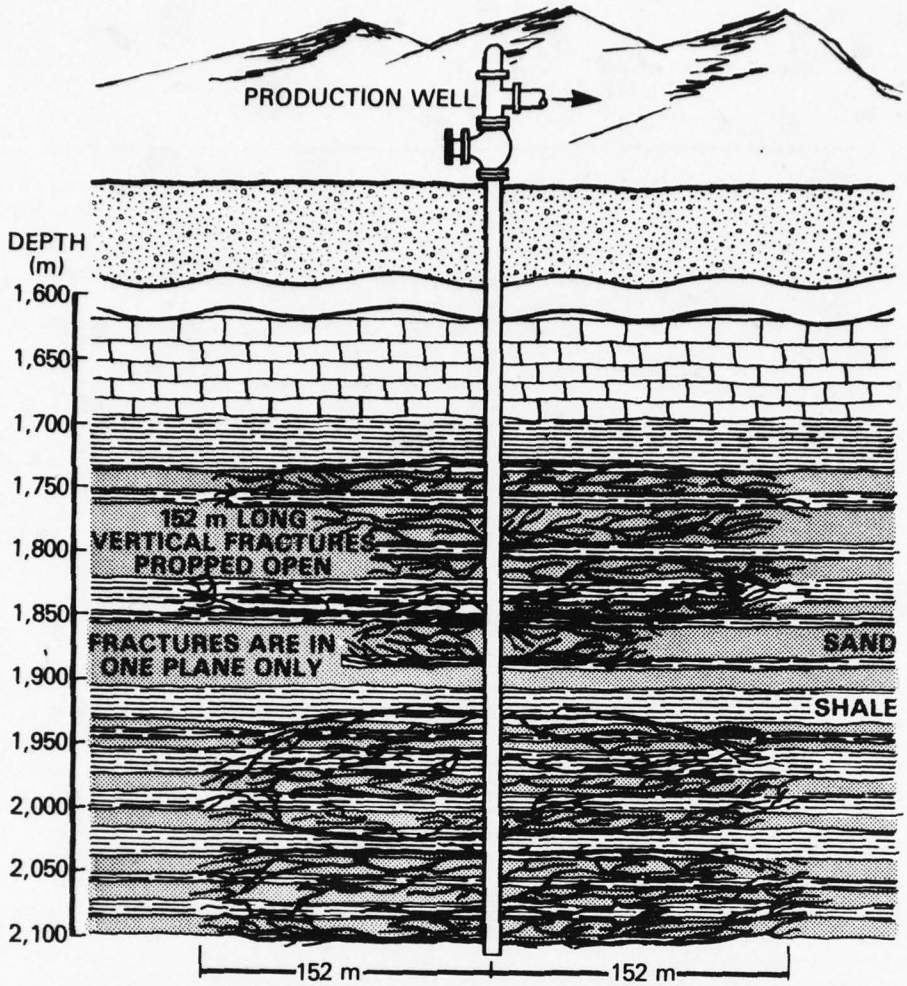
ENHANCED GAS RECOVERY

Enhanced gas recovery in the United States focuses on advanced hydraulic fracturing, chemical explosive fracturing, and directional drilling. These three recovery technologies are of particular interest to the Department of Energy (DOE).

Hydraulic fracturing is a mechanical process for fracturing a reservoir formation. As shown in Figure 3-5, fluid is injected through the wellbore into surrounding formations to overcome natural stresses within the reservoir rock and cause a fracture to develop. Coarse and fine sand is carried along with the fluid to act as a propping material to hold the fracture open after fluid injection is stopped. Fracturing the reservoir rock in this manner provides for greater formation permeability, increasing gas production.

There are two basic approaches to chemical explosive fracturing of gas wells: fracturing a portion of the open hole with nitroglycerin or a shaped-charge explosive, or pumping a chemical explosive slurry into a formation (via a borehole), then detonating the mixture. In the latter, injection pressure for the explosive slurry may be sufficient in some cases to induce hydraulic fracturing of the reservoir. The explosive slurry also can be pumped into existing natural fractures or hydraulic-produced fractures. Current theory involving rock fracture mechanics predicts that the explosive shock wave resulting from detonation of the explosive extends the existing fractures as shown in Figure 3-6, thus increasing permeability and gas production. The goal is to achieve more cost-effective and predictable final results from explosive fracturing for gas production.

Directionally drilled (deviated) wells attempt to use existing natural fracture systems to increase gas production (see Figure 3-7). The natural fracture system of the gas producing zones is studied thoroughly and mapped prior to drilling. Once orientation of the local fracture pattern is determined, an optimum drill site is selected and a well is drilled directionally to maximize the probability of intersecting the fracture system. Each fracture cut by the drill

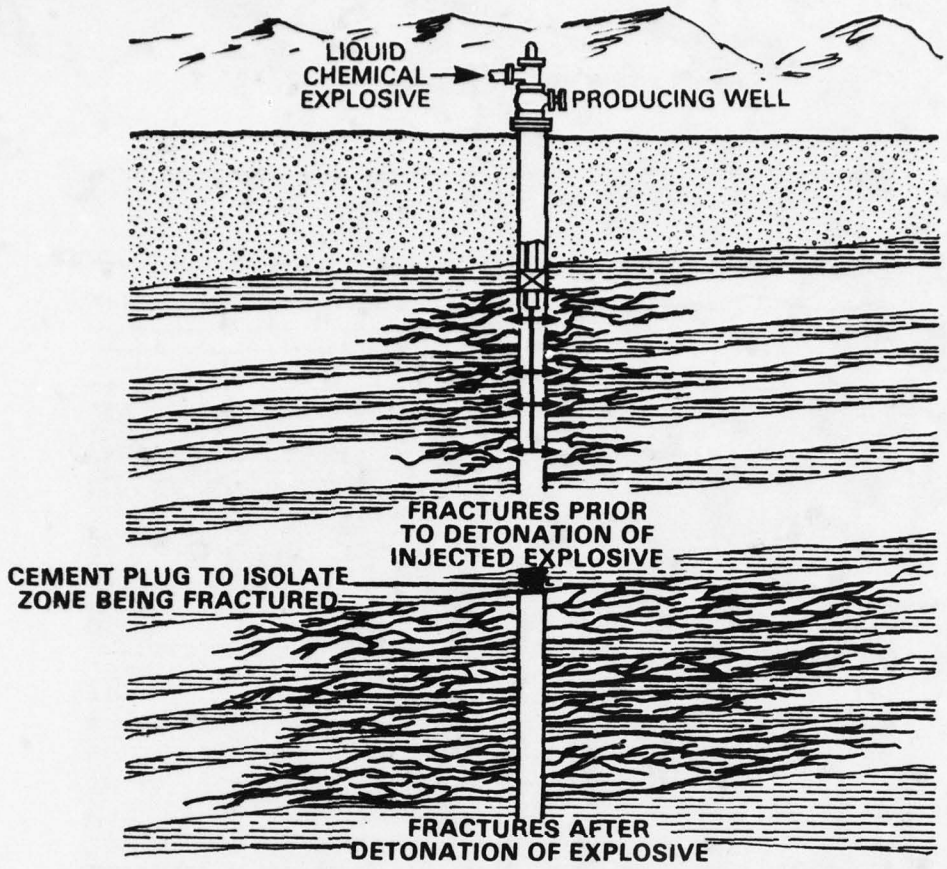


Source: U.S. Department of Energy, "Fossil Energy Program Summary Document, FY 1980, Assistant Secretary for Energy Technology," January 1979.

Figure 3-5. HYDRAULIC FRACTURING PROCESS

column represents a path of higher permeability for gas migration; the greater the number of fractures, the larger the gas flow. In addition, the fracture system can provide conduits for hydraulic or explosive fracturing fluids for subsequent hydraulic or chemical explosive fracturing. The ultimate effect is an extension of existing fractures, an increase in reservoir permeability, and improved production of gas above the production rate expected by drilling conventional vertical wells.

Successful commercial development of unconventional sources of gas will depend to a large extent on the availability of accurate resource characterization data as well as improved recovery technologies. Consequently, DOE is focusing on achieving these technical objectives as well as studying environmental aspects of enhanced gas recovery.[24] Resource charac-

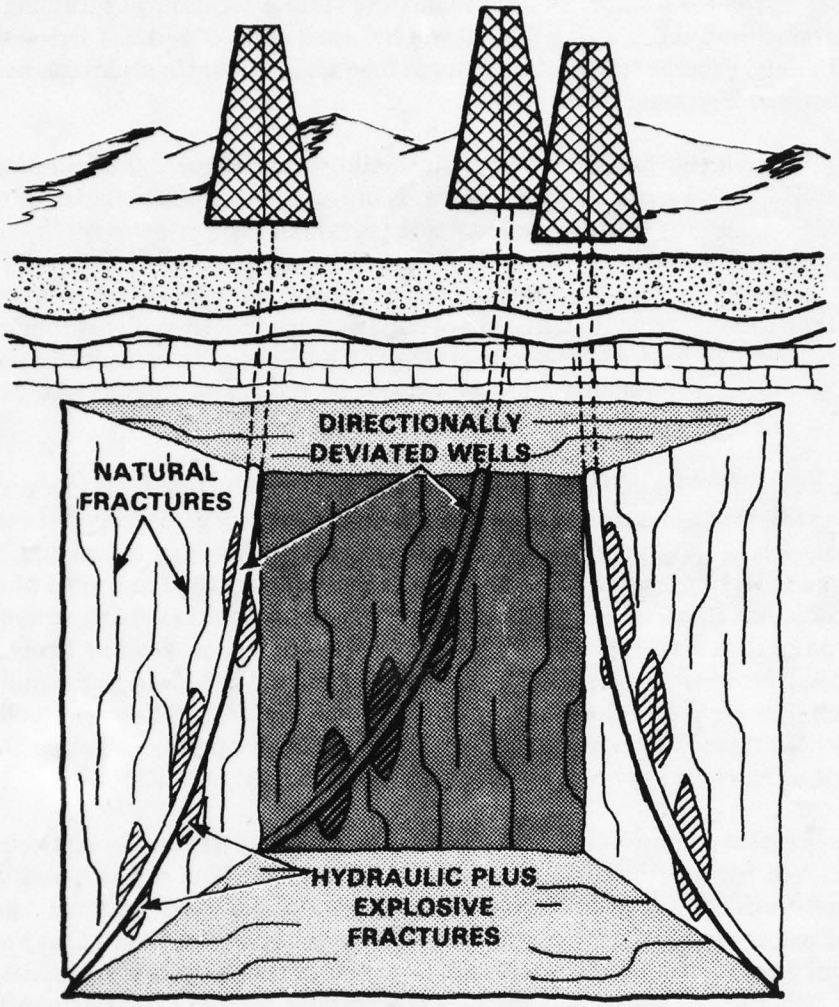


Source: U.S. Department of Energy, "Fossil Energy Program Summary Document, FY 1980, Assistant Secretary for Energy Technology," January 1979.

Figure 3-6. CHEMICAL EXPLOSIVE FRACTURING PROCESS

terization work involves an evaluation of the magnitude and distribution of the resources plus characterization studies to determine the physical and chemical properties affecting reservoir behavior. These support programs involve comprehensive surface and subsurface geological mapping, structural and rock mechanics studies, geochemical studies, mineralogy studies, geophysical logging and interpretation techniques, reservoir engineering studies, and computer data analyses. Environmental research includes control of field projects to ensure they are conducted according to environmental, health, and safety requirements. A thorough understanding of the environmental effects of the new drilling and fracturing techniques is important to the success of enhanced gas recovery commercialization. Additional support work includes economic analyses to assess the cost-effectiveness of various enhanced gas recovery techniques.

To develop the full potential of unconventional gas resources, DOE is emphasizing recovery of gas from Devonian shales, western tight sands, coal seams, and geopressured aquifers. Work on gas-bearing Devonian shales—DOE's Eastern Gas Shales Project—is a



Source: U.S. Department of Energy, "Fossil Energy Program Summary Document, FY 1980, Assistant Secretary for Energy Technology," January 1979.

Figure 3-7. DIRECTIONALLY CONTROLLED WELLS AND EARTH FRACTURE SYSTEMS PROCESS

multidisciplinary effort directed toward increasing natural gas production from Devonian shales of the Appalachian, Illinois, and Michigan Basins. Although active exploration has just begun, almost 3 tcf of gas have been produced from Devonian shales since the turn of the century. One advantage of Devonian shale is that its gas is close to the surface of the earth. The major disadvantage is that the shale density is high and permeability low, which prevent the gas from achieving a high flow rate. Typically, shale wells have had low productivity and long life. Wells producing gas from the brown shale recover only 2 to 10 percent of the gas-in-place; 90 to 98 percent is left in the ground. Furthermore, production is relatively high for the first 5 to 8 years, but the gas flow decreases steadily thereafter.[17] To improve the

recovery rate of gas from shale, DOE is evaluating various technologies (drilling, stimulation, and production); those with potential will be tested and verified in a series of multiple well tests. To date, experiments indicate that gas flow from Devonian shales can be increased through advanced hydraulic fracturing.

DOE's Western Gas Sands Project is directed toward commercial development of the low-permeability (tight) sands of the Piceance, Uinta, and Green River Basins of the Rocky Mountain region. Drilling in the more favorable portion of the low-permeability tight sands basins has yielded over 10 tcf of gas over the last 30 years. Laboratory research is directed toward development of new logging and coring tools, investigation of rock mechanics, mathematical reservoir simulation, and core analysis. Since recovery of gas from tight sands requires extensive fractures, DOE also is developing advanced fracturing techniques. With effective fracturing, an estimated 40 to 50 percent of the gas in the tight sands could be recovered.

Of the existing advanced technologies for improving production from low-permeability sands, massive hydraulic fracturing has proved the most successful, allowing five to 20 times more gas to reach the production well than with conventional drilling techniques.[19] (Typical fracturing operations cost up to $200,000 each; the techniques result in a yield of about 200 thousand cubic feet (Mcf) of gas per well.[25]) The most ambitious massive hydraulic fracturing operation to date was started in November 1978 at the Fallon Field in Texas. The $1.8 million project produced a 60 to 70 m vertical fracture and a 1.6 km horizontal fracture, which will enable one well to drain 640 acres rather than the 200 to 320 acres usually drained from smaller fractures. The eventual yield should be 100 to 200 percent more gas than would be recovered using conventional fracturing techniques in tight rocks.[19,25]

In the Methane from Coal Project, DOE is establishing technically and economically feasible methods for recovering methane gas associated with both minable and unminable (deep or thinly bedded) coal beds. Historically, methane in coal seams has been regarded as a menace; release of the gas during mining has led to explosions that have killed hundreds of miners. Evolution of methane is rapid and copious, particularly in deep mines, and for decades an estimated 80 billion cubic feet (bcf)/year have been lost through expensive ventilation of the mines.[26] Only small amounts (about 0.1 tcf/year) of methane gas associated with coal seams have been produced and sold for local use. A major factor delaying progress in extracting seam methane is the legal uncertainty of ownership. Coal companies own the coal they extract, but few have a clear title to the gas. Still to be determined is whether companies without clear ownership will need special gas leases to extract the methane. The legal barriers currently are greater than the technological hurdles.

The two primary means of extracting methane from coal seams are borehole drilling and hydraulic fracturing. Borehole drilling cuts into coal seams before they are mined; as much as 100 to 200 cubic feet of gas per linear foot of hole is released daily through the hole drilled to lie within a deeply buried seam. One seam in West Virginia has produced more than 2 bcf of gas since 1972. In 1977, a small horizontal borehole produced 60 to 70 million cubic feet (MMcf) of gas in a Utah seam, and a full-scale program by the U.S. Bureau of Mines (BOM) is being planned for the area.[19] Hydraulic fracturing produces a flow rate eight to 20 times faster than that achieved by borehole drilling, and is thus a more

economical means of extracting methane from coal. In addition, BOM's studies of fractured seams indicate that the increased flow rates can be obtained without interfering with subsequent coal mining operations.

The time required for draining the methane from coal seams depends on many factors, including the spacing of holes, but is usually 5 or more years. Tests involving an aggregate of 3,530 m of hole along seams resulted in production of 1.5 bcf of gas in less than 3 years, with at least 5 bcf to be produced eventually.[26]

Federal R&D studies on geopressured aquifers began recently. Theoretically, a facility having 20 wells producing 50,000 bbl/day of groundwater with a saturation capacity of 30 scf of gas/bbl (at 10,000 psi and 120°C) could produce 30 MMcf/day of methane that would need no further processing. Installations 10 times this size are technically possible in some areas.[14] Drilling suitable wells costs about $1.9 million (in 1976 dollars) per well to a depth of 4,572 m.[27]

DOE's first geopressured test well is located in the coastal marsh of southern Louisiana. From a depth of 3,840 m, where pressure is 11,000 psi and the temperature is 120°C, the well is producing up to 10,000 bbl/day of water yielding 500 Mcf of gas.[19] (Gas production is 150 percent higher than originally predicted.) Since 1976, DOE has quadrupled its research budget and hopes to complete at least three geopressure wells by late 1979. Major oil companies have made similar tests and at least two are reported to be planning privately financed projects. Far greater potential awaits further technological advances. Recent research indicates that, at 6,096 m, the saturation capacity of water is about 100 scf of gas/bbl of water at 19,400 psi and 225°C. At 7,620 m, water may dissolve as much as 164 scf/bbl (at 24,500 psi and 270°C).[14]

Recovery of gas from deep wells is also of considerable interest and is feasible with state-of-the-art technology. Development of this unconventional source has been slow, however, because deep drilling is much more expensive and technically difficult than conventional drilling. An average conventional well costs less than $300,000 to complete; a deep well costs between $3.5 million and $15 million. A deep rig must be much heavier and more powerful to grind to such great depths, and a derrick must be capable of lifting 1.5 million pounds of steel drill pipe extending 8 km into the earth.[3] Ultradeep drilling in Oklahoma's Anadarko Basin has penetrated beyond 9,145 m; with better technology, gas production below 15,240 m may become feasible. One well in this basin, completed in May 1977 by the GHK Company, produces 20 MMcf/day from 5,180 m below the surface.[19] Recovery of gas from deep basins can also be competitive economically; Standard Oil of California has sold deep gas profitably on the uncontrolled intrastate market for $2.10/Mcf. Higher prices may be possible on the interstate market as a result of the Natural Gas Policy Act of 1978.

NATURAL GAS PROCESSING

Natural gas is processed to recover liquid hydrocarbons and remove impurities in the gas. Processing yields three basic products: methane, commonly referred to as pipeline gas; ethane, a valuable petrochemical feedstock; and LPG, an important domestic fuel in rural

and small communities. LPG also is used widely as an intermediate material in petrochemical manufacturing and to a growing extent as a motor fuel in trucks and buses.

Processing requirements for produced gas vary widely. Natural gas produced from a nonassociated gas reservoir may require minimal treatment before it is transferred to the transmission line, but associated gas, dissolved gas, and gas condensates may require full processing before they are marketable. Factors considered in selecting the overall processing system are gas type and composition, amount of gas to be treated, product specification, utility costs, environmental aspects, geographic location of the source, available processes (including economic considerations and ease of operation), and proximity of natural gas transmission lines.

Gas Purification[21]

The processes used to remove vapor phase impurities from the gas stream vary in complexity depending on the need for recovery of the impurity or of the material used to remove it. Gas purification generally can be divided into three methods: liquid absorption, solid adsorption, and chemical conversion. Each method is capable of removing the basic impurities (carbon dioxide, hydrogen sulfide, nitrogen compounds, and water) from the gas stream, thereby increasing the heat content of the gas.

In liquid absorption, impurities in the gas phase are transferred to the liquid absorbent either by physically dissolving in the liquid or by reacting chemically with the liquid. The main impurities removed from the gas stream are carbon dioxide, hydrogen sulfide, and carbonyl sulfide when the absorbent is either monoethanolamine (MEA) or diethanolamine (DEA). When the absorbent is aqueous sodium hydroxide, the impurities removed from the gas stream are carbon dioxide, free sulfur, hydrogen sulfide, and low molecular weight mercaptans. Use of glycol as an absorbent removes only water. Combinations of ethanolamines and glycol also are used effectively, however, such combinations have serious drawbacks because they are highly corrosive; their vaporization loss rate is high, especially the amine component; and the solution cannot be reclaimed by simple distillation due to the low vapor pressure of the glycol.

In adsorption, the impurities are adsorbed on the surface of a solid material. Since the quantity of the impurities adsorbed is related directly to the surface area of the adsorbent, these adsorbents have a very high surface area. Typical adsorbents used on a commercial basis for the removal of water vapor, organic solvents, odors, and other vapor phase impurities from the gas are silica gel, activated alumina, activated carbon, and molecular sieves. Molecular sieves differ from the other conventional adsorbents because of their ability to adsorb small molecules selectively, while excluding large molecules, separating on the basis of molecular size differences. Molecular sieves have two additional properties that other conventional adsorbents do not possess: high adsorption capacity at low concentration, and high affinity for unsaturated and polar compounds. These properties make molecular sieves ideal adsorbents for gas purification. A typical example is the 4A sieve, which adsorbs hydrogen sulfide, carbon dioxide, carbonyl sulfide, sulfur dioxide, ethylene, ethane, and propylene, whereas a 3A molecular sieve adsorbs water and ammonia. Furthermore, molecular sieves are widely used for gas drying prior to cryogenic processing as well as for extrac-

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tion of helium from natural gas, air separation, LNG production, and ethane recovery from natural gas using turboexpanders.

Chemical conversion of gas-phase impurities usually is accomplished by heterogeneous catalysis using solid catalysts in fixed-bed reactors. Impurities are transferred from the gas stream onto the surface of the catalysts. The impurities physically are not removed from the gas stream but are converted to compounds that are either not objectionable or can be removed from the gas stream with greater ease than the original component. Additional adsorption or absorption steps may be required to remove the "converted impurity" from the gas stream. A typical catalytic gas purification installation consists of a converter (reaction vessel) and regenerators; heating, cooling, and heat exchange equipment; and a system for removal of the converted impurities. This technique commonly is used to convert high and low molecular weight mercaptans in a gas stream or to oxidize or reduce organic sulfur compounds to either sulfur dioxide or hydrogen sulfide, which are removed easily as previously described. Processes used commercially are Carpenter-Evans process, The Peoples Gas Company Process, The Holmes-Maxted Process, and Beavon Sulfur Removal Process.

Table 3-6 lists major purification processes and the major impurities removed by the process.

Table 3-6. GAS PURIFICATION PROCESSES

Process	Impurity Removed					
	H_2O	CO_2	COS	H_2S	Mercaptans	Free Sulfur
Glycol	X					
Molecular sieve	X	X	X	X	X	
Amine: DEA or MEA		X	X	X		
Caustic: wash (or regenerated)		X		X	X	X[a]
Merox: extraction (or sweetening)					X	
Perco					X	

[a]If hydrogen is not present, free sulfur will not be removed and a Na_2S wash can be used.

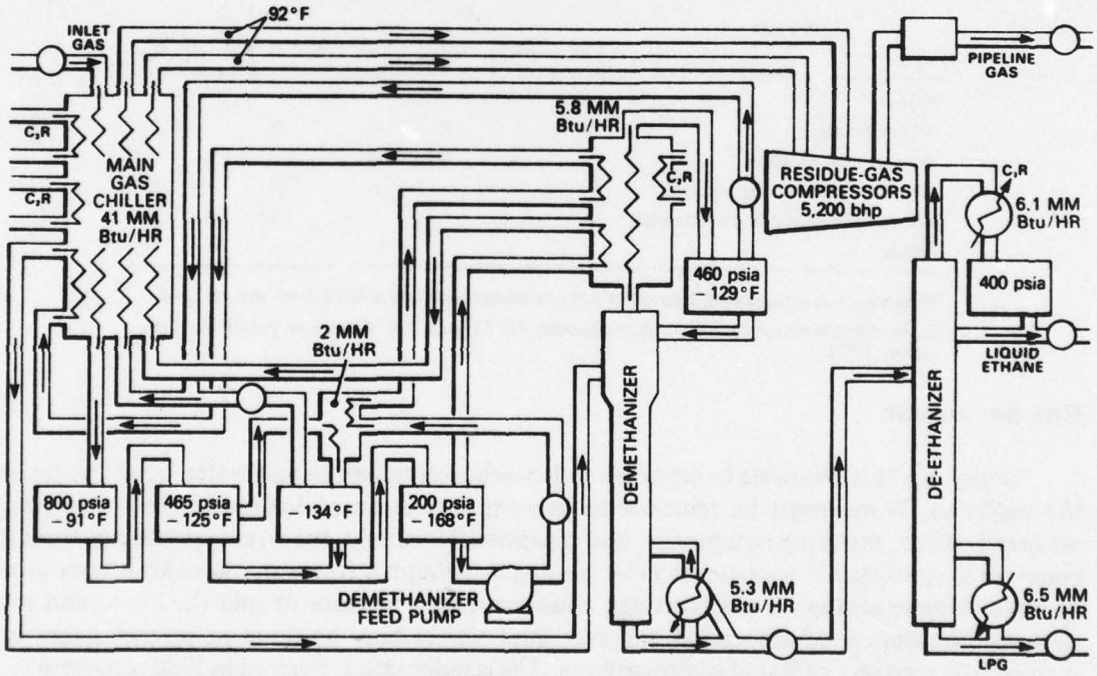
Source: *International Petroleum Encyclopedia, 1977* (Tulsa, OK: Petroleum Publishing Company, 1977).

Gas Separation

Generally, it is desirable to separate hydrocarbon condensate and water from the gas at the wellhead. Water must be removed to prevent formation of hydrates, which can plug wellhead valves, metering equipment, and pipelines. Normally, the stream produced from a reservoir is separated in a single stage by passing it through a free water knockout separator to remove water and sand, then through a low-pressure separator to split the liquid and gas streams. Separation of associated gas and condensates may be done in several stages to increase the recovery of liquid hydrocarbons. The condensate recovered in field separators is scrubbed and transported to a refinery by pipeline along with crude oil and becomes a component of the crude stream which the refinery processes.[29]

When the produced gas has a high content of natural gas liquids, complex processing plants may be required to condition the gas and separate the stream into LPG, natural gasolines, ethane, plant condensate, and small amounts of other hydrocarbon mixtures. Development and growth of cryogenic plants has permitted continually higher recovery of ethane and propane at relatively low initial investment costs and moderate operating costs. Cryogenic-plant ethane recovery capability increased from about 20 percent in plants built before 1967 to over 80 percent in 1976.[2]

For high ethane recovery, the low-temperature (between −73 and −129°C) processes used are cascade (external refrigeration) processes, expander processes, and combinations of both types. The first cryogenic process for ethane recovery was the external refrigeration process (see Figure 3-8). The standard cascade cycle generally has three levels of refrigeration, each progressively colder than the preceding. The first refrigeration level uses propane or freon to refrigerate the natural gas and provide the condensing medium for the second level. The second level refrigerant is usually ethylene, although ethane may be used in place of ethylene. Using ethane requires operating the demethanizer at high pressure where there is lower relative volatility between the components and a close approach to critical temperature and pressure in the reboiler. The second-level refrigerant further cools the gas feed and condenses the third level refrigerant, usually methane, which provides the final refrigeration needed for the gas feed. As compression ratios in these systems are usually greater than 5 to 1, multistage reciprocating compressors are used and several different temperature levels are available for each refrigerant. The methane, ethane, and propane are available from the feed gas. The cascade cycle has the advantage of low power consumption, but the equipment is



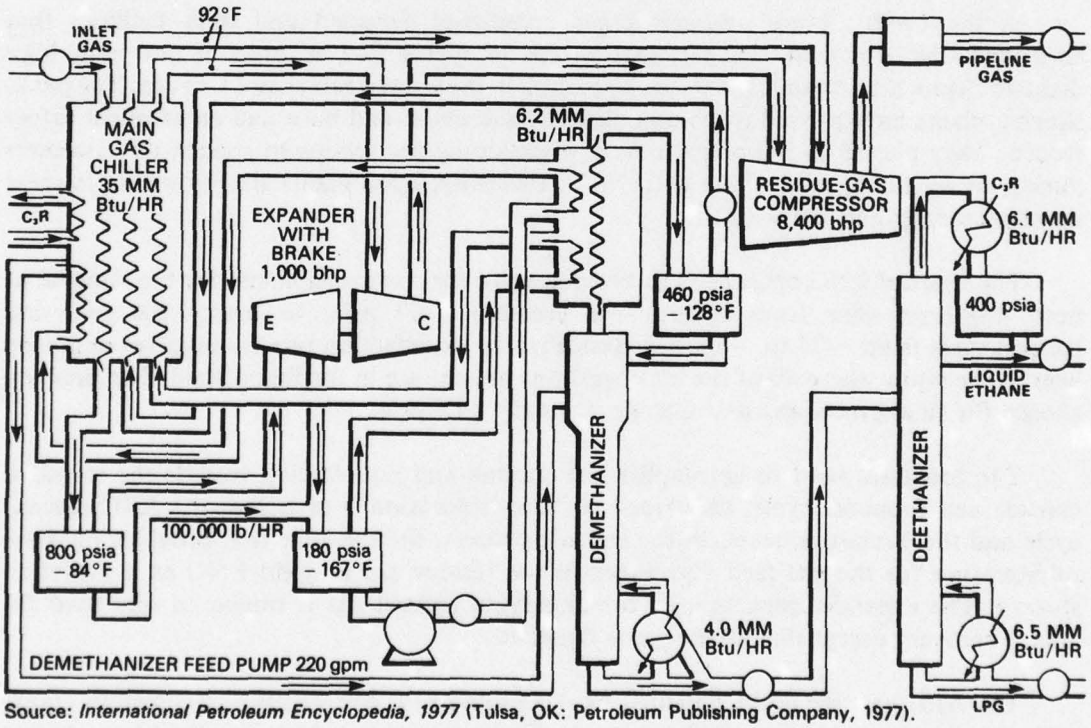
Source: *International Petroleum Encyclopedia, 1977* (Tulsa, OK: Petroleum Publishing Company, 1977).

Figure 3-8. EXTERNAL-REFRIGERATION PROCESS

complex and more costly than other processes. Also, the refrigerants are explosive and considerable control equipment is required.

The first turboexpander cryogenic plant was built in 1963. High-speed expander-compressor units permit simple and reliable refrigeration down to about −107°C. To operate successfully at these low temperatures, molecular sieve desiccants are used to dehydrate the natural gas to prevent hydrate formation.

The turboexpander is a high-speed machine that is relatively rugged in design; its reliability and efficiency are high (90 to 93 percent). Using the turboexpander process (see Figure 3-9), feed gas is dehydrated, then chilled by heat exchange with the residue gas, which is primarily methane. The condensed liquids separate, and the vapor is fed to the expander. A direct-connect compressor recovers the expander energy, boosting the pressure of the condensate stripper overhead gas. Residue gas can be compressed further to any delivery pressure. Alternatively, the compressor can be used to boost the pressure of the feed gas. The turboexpander removes energy from the gas, lowering the temperature below those conditions obtained by simple adiabatic expansion. The liquids condensed at the expander outlet and in the feed chilling step are fed to a separator, then pass to a demethanizer to remove any methane still present. From the demethanizer the liquids go to a de-ethanizer. The liquid bottoms from this unit contain virtually 100 percent of the propane and heavier hydrocarbons in the feed gas, whereas the ethane stream contains about 90 percent of the ethane in the feed gas.



Source: *International Petroleum Encyclopedia, 1977* (Tulsa, OK: Petroleum Publishing Company, 1977).

Figure 3-9. EXPANDER PROCESS

There are several advantages to the turboexpander system: the final cryogenic operating temperature is obtained from the expander rather than from costly external refrigeration; product separation pressure is set to give the most desirable equilibrium conditions; plants are compact and inherently simple; capital costs and operating costs are usually low, as much as 40 percent savings over conventional ethane recovery systems; and maintenance requirements are low. A disadvantage is that the expander process requires about 20 percent more gross horsepower and 9 percent more net horsepower than the cascade plant. However, cascade plants are more complex because of the required heat exchange equipment. Accordingly, a complete economic evaluation is needed to choose the type of process to be used.

Liquefied Natural Gas[2,31,32]

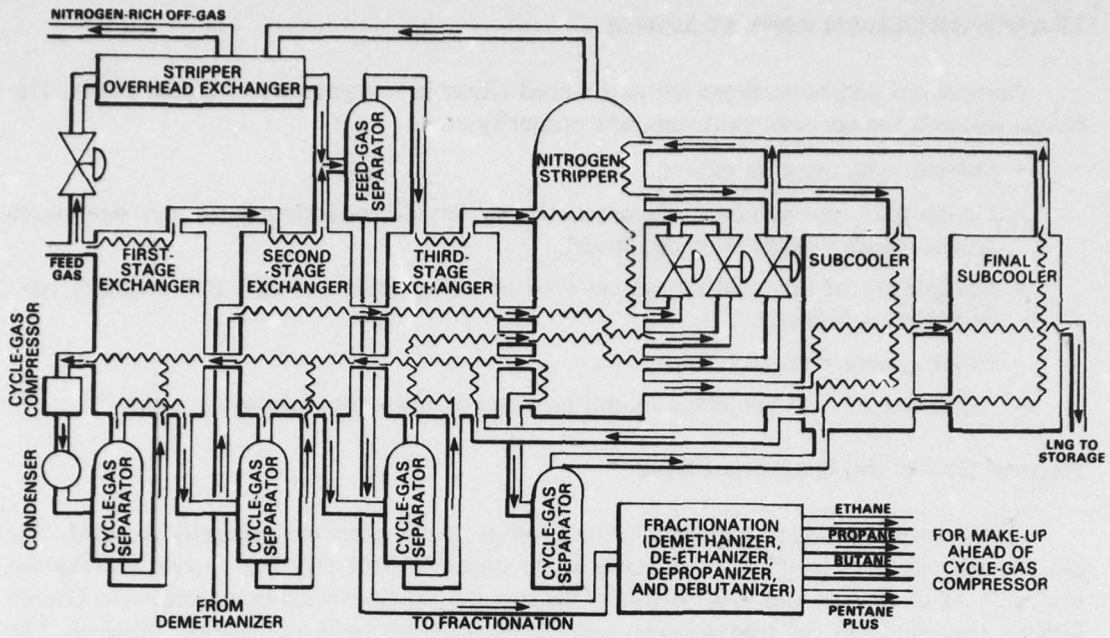
The methane, or residue gas, from the separation process may either be compressed and transmitted by pipeline to its markets, or it may be liquefied at about $-160°C$, to reduce its volume and thus make shipping over long distances economically feasible. A facility for liquefying natural gas was built in Cleveland in 1941, but failure of a storage tank in 1944, which caused a disastrous accident taking 135 lives, set the industry back two decades. Development of improved materials for storing cryogenic liquids and new safety precautions for handling them—primarily by the National Aeronautics and Space Administration and the Department of Defense—resulted in renewed interest in liquefied natural gas (LNG).

In the 1960s, several municipal gas companies designed and built facilities that employed LNG for peak shaving, that is, for supplying fuel at times of unusually high demand. More than 60 such plants are operating in the United States and Canada. The peak-shaving plants have proved to be economically successful and have had an excellent safety record. They played an important role in maintaining gas service to residential customers during the unusually cold winter of 1976-77. Presently, LNG plants are being built in great numbers throughout the world.

The heart of LNG operations is the equipment for compression and for the removal of heat. Pressures vary from atmospheric pressure (14.7 psia) to nearly 800 psia and temperatures from -73 to $-160°C$. Basically, the liquefaction process involves removing heat to the point where all of the hydrocarbons present are in the liquid state. The pressure chosen for final processing and storage is usually 14.7 psia.

The processes used to accomplish the cooling and liquefaction include the standard cascade and expander cycles (described in "Gas Separation") as well as the ARC cascade cycle and the Tealarc process. In the cascade process, the methane that provides the final refrigeration for the gas feed also subcools the residue gas to yield LNG as it moves to storage. The expander process used for liquefying natural gas is similar to that used for ethane recovery except that all the gas is liquefied.

The ARC cascade cycle, patented by Air Liquid Ltd. of Canada and shown in Figure 3-10, uses only one refrigerant compressor. The refrigerant, which is a liquid condensed from the gas being liquefied, may have many compositions and thus allows quite small



Source: *International Petroleum Encyclopedia, 1978* (Tulsa, OK: Petroleum Publishing Company, 1978).

Figure 3-10. ARC CYCLE

temperature differences between successive refrigerants. Piping arrangements are simpler than for the standard cascade cycle and only two pressure levels are required. The feed gas is liquefied partially in the first two exchangers, then passes into the feed gas separator. The liquid is fractionated into components that can be added before the compressor to adjust the refrigerant composition to obtain the amount of cooling required. The gas from the feed gas separator goes to the third stage exchanger for liquefaction and subcooling. The final cooling is accomplished by expanding and vaporizing a bit of the subcooled LNG in cold methane exchangers. Initial capital investment for an ARC plant may be 15 to 20 percent less than the standard cascade cycle, but 8 to 10 percent more refrigeration horsepower is required, which increases operating costs.

The Tealarc process is a two pressure process using hydrocarbons from the process gas as refrigerants. The feed gas is first compressed to 580 psia in an axial compressor, then cooled and condensed in a series of heat exchangers. As the gas proceeds through the exchangers, the heavier hydrocarbons condense and the molecular weight of the refrigerant becomes progressively lower. The refrigerant liquids vaporize on the shell sides of two exchangers, one at 90 psia and the other at 30 psia. There are two stages of axial compression, the low pressure unit taking in vapor at 20 psia and compressing it to the inlet pressure of the high-pressure unit. Adjustable stator blades and bypass controls give the flexibility needed for high performance. Both the ARC process and the Tealarc process require the various hydrocarbons present in natural gas as it comes from the well to fix the refrigerant compositions. Thus, the standard cascade cycle and the expander cycle may be the only workable processes for natural gas stripped of ethane and LPG.

TRANSPORTATION AND STORAGE

Natural gas can be transported and stored either in the gaseous or liquid phase. The means selected for gas transport depends primarily on:

- Distance gas must be moved.
- Geographic and geologic characteristics of terrain, including land and sea routes across which the gas is to be moved.
- Complexity of distribution system (few or many source points, few or many consumption terminals).
- Environmental factors.
- Construction and projected operating costs of the transportation system.

Natural Gas in the Gaseous Phase

When natural gas is transported in the gaseous phase, pipelines generally are used. The gas pipeline network in the United States is the nation's most efficient energy distribution system.[39] As of 1976, about 410,370 km of natural gas pipelines were in service in the United States—three-fourths for transmission and the balance for field and storage pipeline. The total marketed volume of gas through this system was slightly more than 17.5 tcf.

Before a company can build a pipeline, or enlarge an existing line, it must meet legal, engineering, safety, and economic requirements established and enforced by the Federal Energy Regulatory Commission (FERC). The company must have contracts with producers of natural gas with sufficient supply to last a reasonable time period (normally 20 years), show that it has a market for the gas at the delivery end of the line, show that a sufficient demand exists for energy (by present and future consumers), and demonstrate the engineering capability and financial resources necessary to build a pipeline that operates safely and efficiently. Additional public protection is provided by the Gas Pipeline Safety Act of 1968. This law allows the Department of Transportation to establish federal safety standards for transporting natural gas by pipeline.

To select the best route for a gas pipeline from producing wells to the receiving communities, aerial surveys are conducted. These surveys indicate which route would disrupt agricultural and urban areas the least. A careful on-the-ground survey of the route selected from an aerial survey is conducted to determine if minor changes in the pipeline route are required. Environmental assessment studies are conducted, and the pipeline company purchases and clears the pipeline right-of-way. A corridor about 30 m wide usually is required to provide for construction and accommodate pipe-laying and welding equipment. At intervals along the pipeline right-of-way, the company purchases selected tracts of land for building compressor stations and other facilities needed for pipeline operation.

The most common size of the installed gas pipeline ranges from 50.8 to 91.4 cm. There has been a strong trend toward larger-diameter lines, from 106.7 cm diameter upward. Pipe sections usually are a minimum of 12.2 m long and may be 18 or 24 m. The total weight of steel pipe used in a long-distance pipeline is impressive—a pipeline having a 1.3 cm thick wall and 76.2 cm diameter weighs more than 225 metric tons/km.[4]

Gas pressures in long-distance pipelines range from 500 to 5,000 psi, a common pressure being 1,000 psi. Pipeline pressure is maintained by using compressor stations spaced every 80 to 160 km along the pipeline. Stations for reducing line pressure, located near points of consumption, are called city gates. These stations meter the gas leaving the main pipeline at a given point as well as reduce the pressure.

Gas pipelines also are constructed under water (river, marsh, or ocean). The predominant industry effort in recent years is construction of pipelines in the open ocean at increasingly deeper levels, as a result of the expanding search for offshore oil and gas. Lines now are being laid in water depths of over 120 m and cover distances as long as 320 km from field to shore.

The two main reasons for design differences between land and marine pipelines are the stresses incurred in getting the pipeline to the sea bottom and the necessity of keeping the line stable and in place while it is exposed to forces induced by currents and waves. However, pipeline sizing, pump and compression equipment design, automation systems design, and many of the corrosion control procedures are the same, regardless of whether the pipeline is located on land or at sea. Construction variables affecting the cost of marine pipelines include pipe material and wall thickness (which depends on the laying stresses); welding requirements; weight-coating requirements; environmental effects, such as the magnitude and direction of wind and well; unusual weather; water depth; sea bottom conditions; shore approaches; time of year; distance of the job site from the normal base of operations of the barges; line crossings; and type of equipment being used.

Natural gas in the gaseous phase is stored in underground reservoirs located in non-gas-producing regions as well as near producing gas fields in at least 34 states of the United States. Some of the storage reservoirs are operated by pipeline companies, but most are owned by local gas companies that serve metropolitan areas. Underground reservoirs are filled with gas from pipelines during summer months when excess fuel exists because of lower consumption. This procedure allows for fairly steady operating rates for producing wells and pipelines at all times of the year. The steady production rate also ensures more gas production over a longer period of time from a gas field.

The most common type of underground reservoir now storing gas is a former producing gas or oil field. Since supplies remaining in these fields are too small and at too low a pressure to justify continued production, pipeline gas can be pumped into these reservoirs through the same wells that once extracted oil or gas. The stored gas is maintained under similar pressure conditions as originally existed in the reservoir.

Another kind of underground storage reservoir is an aquifer, which is a porous, permeable rock formation saturated or partly saturated with groundwater. The aquifer is usually confined from above by impervious materials. Injection wells are drilled into the aquifer and gas is forced into the pores under pressure. As gas pressure increases, the gas displaces the water downward or laterally into the porous rock, making room for the gas. In the United States, at least eight states use some 44 aquifers for gas storage. An abandoned coal mine in Colorado and salt domes in Michigan and Mississippi are two other types of gas storage reservoirs that have been developed.

Liquefied Natural Gas[2,31,32]

When natural gas is liquefied, its volume is reduced to 1/600 of that of its gaseous volume. This reduction in volume makes shipping this premium fuel over great distances feasible.

With the depletion of gas reserves in the United States, the incentive to import LNG for base-load operations is increasing. A base-load terminal would receive the LNG on a regular basis from a fleet of tankers, store it in large tanks, and revaporize it continuously to distribute through the pipeline system as fuel. The 35 LNG tankers now in operation have an average capacity of 46,000 m^3 of liquid; 41 other tankers being designed or built have an average capacity of 124,000 m^3. The tankers projected for large-scale operations will each have a capacity of up to 165,000 m^3. The storage tanks at the receiving terminal may be two to four times larger than the 50,000 m^3 tanks typical of present peak-shaving facilities.

Since it is expensive to build and operate a large and highly specialized vessel, operators seek to minimize the amount of time such a ship is idle. This approach has led to the development of elaborate and efficient techniques for loading and unloading. Pipes carrying LNG between a ship and a tank on shore have the capacity to pump the LNG at a rate as high as 4 m^3/s (50,000 gal./minute).

LNG is flammable when it vaporizes in air, but is innocuous inside a storage tank. Accordingly, LNG storage facilities and tankers are designed to prevent accidental release. To prevent its vaporization, LNG must be stored in double-walled tanks built of material that retains its strength at $-160°C$. High-nickel steels, some aluminum alloys, and prestressed concrete have been tested extensively with LNG and found to be suitable for the construction of the inner tank. The insulation that is a requisite for every tank holding LNG is put outside the structure that contains the liquid and held in place by an outer tank. The insulation is usually the noncombustible material known as perlite. A typical tank at a storage facility holds some 90,000 m^3 of LNG. Federal regulations stipulate that each tank be surrounded by an impoundment dike capable of containing the entire contents of a fuel tank and that a buffer zone be provided between the dike and the boundary of the facility to prevent damage in case of accidental release of LNG.

The tanks on ships carrying LNG also must have double walls and insulation more than a meter thick to reduce the vaporization rate. There are three basic tank designs for shipping. The first uses freestanding tanks that are separate from the hull except for support members. The outside of each tank is insulated, and a clearance may be left between the insulation and the hull. The second design uses membrane tanks, which receive support from the hull through load-bearing insulation. The third design uses spherical tanks that are built outside the ship, then lowered into prepared spaces during the final stages of construction. With all three types of tanks, the primary container for the liquid is made of welded metal. In addition, the freestanding tanks and the membrane tanks are required by the U.S. Coast Guard to have a secondary cryogenic barrier. As a result, accidents such as ramming and grounding are not likely to cause the release of cargo from a ship carrying LNG.

In addition to preventing accidental release of LNG from the tanks, standard operating procedures have been developed for preventing rollover inside the tanks. Rollover can occur

when mixtures of LNG with differing composition and density stratify. For example, a new load of LNG added into the bottom of a tank in which LNG is already stored tends to remain at the bottom because it has a higher density than the material already in the tank and is warmer. Because of the difference in density, a two-layer system is created. In a two-layer system, the liquid in each layer still flows convectively, but the denser fluid is not sufficiently buoyant to enable it to penetrate the less dense upper layer. Thus, energy is stored in the denser layer. In time, the transfer of heat and mass between the layers tends to equalize the difference in density. The layers then may mix rapidly. As the material attempts to achieve thermal equilibrium, the intrusion of the warm bottom layer leads to a rapid generation of vapor to release the excess energy that was accumulated while there were two layers. As the contents of the tank suddenly mix, the pressure in the tank begins to rise, and could increase enough to cause serious structural damage if the tank is not vented to relieve the pressure. To prevent stratification, the less dense liquid may be loaded into the bottom of the tank and the denser into the top. Another option is to always load the tank from the top; then, even if stratification occurs, the time required for rollover is much longer than the residence time of LNG in a storage tank at a typical import terminal.

Liquefied Petroleum Gas[29]

LPG, which is used as a gas, is transported and stored as a liquid. LPG is a gas under ordinary temperatures and pressures, but must be kept under moderate pressure if it is to be handled as a liquid. All modes of transportation that can be used for petroleum products can likewise be used to transport LPG, including pipelines, tankers, barges, tank cars, tank trucks, and cylinders. Pipelines for transporting LPG are most common in the production areas, running from plants to terminals, to central storage, to large-volume petrochemical facilities.

Storage is necessary at the point of production, at the point of distribution, and at the point of consumption. The producer and the distributor also may have secondary storage installations. Producer storage may be underground (dissolved salt cavities or mined caverns) or aboveground (spheres or horizontal or vertical cylindrical tanks). Most producer storage is at the point of production, although there is a growing tendency to construct and operate large-volume storage nearer major consuming areas. Most of this secondary storage is located near pipelines or at water terminals. However, several major storage terminals receive their product by tank car during the "off" season.

Storage by the distributor is largely in horizontal cylindrical containers at 250 psig, which is suitable for commercial propane, all butane-propane mixtures, or commercial butane. Tanks having a design pressure of 125 psig (the minimum standard) can be used only for commercial butane or the low-vapor-pressure butane-propane mixtures. (The use of minimum design pressure tanks is an important economic consideration, particularly in large-volume storage.) Although 12,000, 18,000, and 30,000 gal. tanks are the most common for bulk storage plants, these tanks may vary in capacity from 1,000 to 30,000 gal. A few distributors have developed their own underground storage where their operations are large enough to justify the investment and where their marketing area is close to suitable geological formations.

Consumer storage may include all types and sizes mentioned above for producers and distributors. The size and type will vary with the load demand by the domestic, commercial, industrial, petrochemical, or utility user.

ENVIRONMENTAL ISSUES

Natural gas is clean-burning and has less environmental impact than any other fossil fuel.[30,33] Environmental problems associated with exploring and drilling for natural gas are the same as those encountered in drilling for oil (see Chapter 2).

Most of the potential environmental problems are associated with LNG. The major hazard of LNG is fire, as it tends to burn back through the vapor toward the source. Rollover could occur whereby vented gas could ignite and the pressure in the storage tank could increase enough to cause serious damage. If LNG is spilled, the vapor may cause asphyxiation and the low temperature may result in frostbite for anyone in the immediate area. Another problem is whether a fire in a cloud of vaporized LNG might detonate and produce a damaging blast wave.

NATURAL GAS PRICING STRUCTURE

The pricing structure for domestically produced natural gas involves wellhead prices (also referred to as contract or field prices) and wholesale prices. Buyers of gas reserves at the wellhead are usually natural gas pipeline companies seeking gas to deliver under long-term contract to industrial consumers and retail gas public utility companies. Wholesale prices depend on wellhead prices and delivery charges for transporting the gas from wellhead to final consumer. The pipelines offer instantaneous deliveries of gas as it is burned by the final buyer, and for this they charge a markup over their field purchase prices.

Federal Regulation

From the early 1960s to 1978, a dual price structure existed for domestically produced natural gas: the Federal Power Commission (FPC) regulated the contract prices of natural gas committed to interstate sales and interstate transportation profit margins, while states regulated intrastate sales. FPC originally set rates for different regions of the country based on regional average costs of production. Temporary price ceilings were set at the 1958-59 market price levels; new gas committed to interstate pipelines after 1961 had to be priced at these levels.

Throughout the 1960s, prices of new contracts for gas going to the interstate pipelines remained nearly constant. The weighted average new contract price was $0.182/Mcf in 1961 and $0.198/Mcf in 1969. The average wellhead price of natural gas (called a "rolled in" price) changed slowly as prices rose on new filed contracts, since new contracts in any one year provide only 5 to 15 percent of all gas under contract, and increased only from $0.164/Mcf to $0.175/Mcf between 1961 and 1969, as depleted old contracts at lower prices were replaced by new contracts at the ceiling levels close to $0.190/Mcf.[34]

FPC's policy was to allow wholesale prices to equal the historical average field price paid for gas at the wellhead plus the markup. Markups (for interstate pipelines) depended on the historical costs of transmission and the regulated transportation profit margins. Wholesale prices rose only from $0.320/million Btu in 1962 to $0.334/million Btu in 1970. For comparison, oil wholesale prices during this period increased from $0.345/million Btu to $0.398/million Btu, and coal wholesale prices rose from $0.256/million Btu to $0.312/million Btu.[34]

When natural gas shortages appeared in 1971, the regulatory freeze was reversed in a series of FPC rate decisions that substantially increased field prices. FPC offered producers several price incentives to stimulate exploration and increase reserves. For producing areas that contained more than 85 percent of already proved reserves, FPC increased prices from $0.030 to $0.052/Mcf for new contracts signed that year. For all future contracts, the FPC began a proceeding to set national ceiling prices, signaling its intention by setting preliminary prices in one region that were $0.070/Mcf higher than those previously in effect. Further increases were promised through the new procedure of certifying sales above the prevailing area price ceilings. As a result of these policy changes, new contract prices of natural gas increased substantially in the early 1970s. The weighted average new contract price increased from $0.198/Mcf in 1969, to $0.336/Mcf in 1972, and to about $0.360/Mcf in 1973. The average wellhead price, as indicated in Table 3-7, increased from $0.186/Mcf in 1972 to $0.791/Mcf in 1977. Despite the increases, as of 1976, wellhead prices of natural gas in the interstate market were only 25 percent of the Btu equivalent price (the price paid for quantities of various energy sources with equivalent heat content) of imported oil.[35]

Table 3-7. AVERAGE WELLHEAD PRICE OF NATURAL GAS[a]

Year	Price ($/Mcf)
1972—Average	.186
1973—Average	.216
1974—Average	.304
1975—Average	.445
1976	
January	.539
February	.540
March	.542
April	.545
May	.548
June	.578
July	.575
August	.601
September	.603
October	.617
November	.630
December	.644
Average	.580
1977	
January	.671
February	.710
March	.749
April	.772
May	.767
June	.823
July	.831
August	.823
September	.833
October	.840
November	.832
December	.844
Average	.791

[a]Annual data are from the appropriate agencies of the individual producing states; monthly data are estimated primarily on the basis of values reported by state agencies in New Mexico, Oklahoma, and Texas.

Source: U.S. Department of Energy, "Monthly Energy Review," DOE/0035/12, December 1978.

At federally regulated prices, natural gas was highly attractive to industry and utilities, which used the equivalent of about 6 million bbl of oil/day, while new households had to turn to electricity. In addition, the fact that only interstate sales were regulated discouraged the distribution of natural gas from producing to nonproducing states, and new onshore gas production went primarily to the intrastate market. From 1973 to 1975, only 19 percent of new reserve additions were committed to the interstate market, causing serious regional shortages. Contract prices in early 1977 for new gas in the intrastate market ranged from $1.60/Mcf to $2.25/Mcf, while the highest price allowed for long-term interstate gas purchases was $1.45/Mcf. Table 3-8

shows wellhead and wholesale prices reported by major interstate pipeline companies for purchases and sales from 1975 through 1977. Intrastate natural gas wellhead prices for selected states are presented in Table 3-9. For comparison, Table 3-10 shows the average retail prices for natural gas sold to residential customers for heating.[35]

Table 3-8. NATURAL GAS PRICES REPORTED BY MAJOR INTERSTATE PIPELINE COMPANIES

Year	Wellhead Price ($/Mcf)			Wholesale Price ($/Mcf)		
	From Domestic Producers	From Canadian and Foreign Sources	Total Purchases	To Industrial Users[a]	To Resellers[b]	Total Sales
1975						
January	.304	1.040	.358	.678	.709	.712
February	.295	1.059	.352	.701	.740	.743
March	.335	1.025	.388	.704	.777	.778
April	.328	1.028	.383	.711	.823	.819
May	.347	1.006	.398	.711	.837	.828
June	.353	.989	.402	.722	.851	.839
July	.367	1.011	.417	.739	.846	.836
August	.355	1.410	.433	.734	.865	.851
September	.365	1.411	.444	.728	.859	.847
October	.360	1.401	.443	.772	.859	.854
November	.365	1.625	.467	.778	.867	.864
December	.358	1.618	.459	.807	.876	.875
1976						
January	.383	1.640	.487	.882	.901	.906
February	.397	1.653	.501	.882	.938	.941
March	.394	1.645	.499	.868	.920	.922
April	.405	1.643	.515	.890	.965	.964
May	.422	1.650	.527	.874	.992	.985
June	.437	1.666	.540	.898	.994	.988
July	.438	1.684	.538	.946	1.027	1.020
August	.564	1.677	.657	.982	1.053	1.046
September	.686	1.837	.779	1.039	.931	.947
October	.576	1.901	.693	1.067	1.058	1.062
November	.526	1.824	.636	1.135	1.067	1.075
December	.540	1.894	.657	1.331	1.178	1.186
1977						
January	.594	2.018	.716	1.432	1.243	1.254
February	.634	1.997	.764	1.306	1.304	1.310
March	.698	2.004	.834	1.293	1.321	1.325
April	.653	1.907	.765	1.281	1.310	1.311
May	.691	1.913	.805	1.281	1.339	1.335
June	.692	1.886	.796	1.253	1.351	1.342
July	.721	1.877	.818	1.343	1.359	1.357
August	.711	1.855	.815	1.335	1.340	1.339
September	.718	1.947	.840	1.318	1.357	1.354
October	.742	2.119	.874	1.339	1.356	1.356
November	.743	2.142	.871	1.349	1.417	1.415
December	.739	2.165	.868	1.385	1.322	1.331

[a]Represents direct sales by pipeline companies to industrial users. Does not include sales to industrial users by resellers.

[b]Includes the cost of gas to the distributing utility at entrance of distribution system or point of receipt.

Source: U.S. Department of Energy, "Monthly Energy Review," DOE/0035/12, December 1978.

Table 3-9. INTRASTATE NATURAL GAS PRICES FOR SELECTED STATES BY TYPE OF CONTRACT[a]

Year	Wellhead Price ($/Mcf)									
	California		Kansas		Louisiana		Oklahoma		Texas	
	New Contracts	Renegotiated or Amended	New Contracts	Renegotiated or Amended	New Contracts	Renegotiated or Amended	New Contracts	Renegotiated or Amended	New Contracts	Renegotiated or Amended
1975										
January	.7500	.7689	.5530	—	.9804	1.0296	.9599	.7603	1.3990	1.6404
February	—	—	—	—	1.2868	1.1306	.9730	.6449	1.5472	1.6311
March	—	—	—	—	1.1578	1.2589	1.0770	.5505	.9666	.9750
April	—	—	.6465	.4524	1.4978	1.3481	1.3258	.8779	1.6009	1.7632
May	—	—	—	—	1.2680	1.2353	1.2931	1.0656	1.5672	1.5859
June	—	.5368	.6500	—	1.3091	1.2957	.9422	1.2029	1.6500	1.8754
July	—	.6551	—	—	1.1722	1.2563	1.3387	1.1462	1.8322	1.7822
August	—	.7500	1.9824	—	1.3287	1.1420	1.3677	1.2121	1.5187	1.3250
September	—	.8600	1.5289	.7038	1.2189	1.4123	1.4373	1.0669	1.6987	1.8077
October	1.3553	—	—	—	.7516	1.1760	1.4309	1.4414	1.6810	1.8730
November	—	—	1.5795	1.3902	1.3842	.7165	1.4061	1.3315	1.4943	1.8217
December	—	—	—	.8000	1.3964	1.3192	1.3250	1.5386	1.6720	1.4090
1976										
January	—	.8397	1.0381	.8454	1.3875	1.3123	1.4987	1.0939	1.8105	1.9331
February	—	.4000	—	1.0968	1.2500	1.4530	1.3372	1.4671	1.7663	1.9154
March	—	—	1.5036	—	1.4566	1.5539	1.6283	1.6857	1.7870	1.7644
April	1.9500	—	1.5000	—	1.4299	1.5405	1.6212	1.4830	2.0260	1.5295
May	1.2200	.6039	1.8039	1.4984	1.2554	1.0605	1.5635	1.6402	1.5400	1.9722
June	—	—	1.1445	1.5082	1.4711	1.3767	1.6956	1.6814	1.7801	1.9293
July	—	1.1715	1.3757	1.5083	1.2755	1.4171	1.4820	.9500	1.5119	1.7623
August	—	.9738	—	—	1.3870	1.6423	1.5181	1.7149	1.5798	1.9881
September	—	—	—	1.2568	1.6410	1.5639	1.6485	1.7200	1.8407	1.9766
October	—	—	—	1.1172	1.4464	1.4991	1.6348	1.6116	1.9658	1.8980
November	—	—	1.5082	1.4421	—	1.3191	1.6257	.9073	1.8680	1.8282
December	—	.9747	1.6073	—	1.9451	1.5245	1.6755	1.7598	1.9871	2.0254
1977										
January	—	1.0558	1.5549	—	1.5582	1.3765	1.7235	1.6749	1.9336	2.0406
February	—	1.0727	1.2166	—	1.4133	1.2084	1.4786	1.3127	1.8555	2.0372
March	1.1979	1.1628	1.4818	—	2.1943	2.0897	1.6857	1.6828	1.9714	1.9083
April	—	—	1.3710	1.5638	2.1641	1.5035	1.6561	1.6789	1.9222	2.0544
May	—	1.0720	1.1900	—	1.9753	1.5897	1.5662	1.7109	2.0406	2.0127
June	—	1.1221	.9149	—	1.8021	1.6961	1.6669	1.6951	1.9454	2.0641
July	—	1.3902	.8857	1.7453	1.7490	1.6964	1.7295	1.6825	2.0696	2.0246
August	—	—	1.3197	.9049	1.7799	1.6666	1.6433	1.5846	1.8696	1.8357
September	—	—	—	1.3666	1.6372	1.6249	1.7178	1.7270	1.6714	2.1244
October	—	—	—	.7563	2.0126	1.4288	1.4844	1.7501	2.0273	2.0403
November	1.3500	1.3615	1.5039	1.0580	—	1.8297	1.6626	1.7478	1.8694	1.9911
December	—	1.2440	1.4709	1.6659	1.9642	1.5423	1.6032	1.7349	2.0765	2.0332

[a]Prices are for FERC jurisdictional natural gas companies selling more than 1 bcf/year in interstate commerce.

Source: U.S. Department of Energy, "Monthly Energy Review," DOE/0035/12, December 1978.

Table 3-10. AVERAGE RETAIL PRICES FOR NATURAL GAS USE SOLD TO RESIDENTIAL CUSTOMERS FOR HEATING

Year	Price ($/Mcf)
1975	
January	1.412
February	1.447
March	1.461
April	1.506
May	1.537
June	1.557
July	1.547
August	1.554
September	1.594
October	1.606
November	1.662
December	1.702
1976	
January	1.714
February	1.752
March	1.770
April	1.784
May	1.808
June	1.832
July	1.845
August	1.858
September	1.912
October	1.950
November	1.983
December	2.083
1977	
January	2.138
February	2.170
March	2.199
April	2.237
May	2.270
June	2.273
July	2.299
August	2.301
September	2.304
October	2.351
November	2.384
December	2.373

Source: U.S. Department of Energy, "Monthly Energy Review," DOE/0035/12, December 1978.

Deregulation[36]

The Natural Gas Policy Act (NGPA) of 1978 (Public Law 95-621), signed into law on 9 November 1978, substantially transformed the regulatory framework governing producer sales of natural gas. DOE's FERC has primary responsibility for administering and enforcing the NGPA. In accordance with the NGPA, FERC issued interim final regulations on 1 December 1978.[37]

The NGPA, summarized in Table 3-11, provides for new price and contract regulations, makes emergency provisions for natural gas supplies, and sets forth curtailment policies. It establishes a series of maximum prices for several categories of gas, including gas destined for both the intrastate and interstate markets. These prices are to be adjusted monthly for inflation, although some prices will be allowed to increase at a faster rate. Price controls are to be lifted entirely from new gas by 1 January 1985, and intrastate gas selling for more than $1.00/million Btu also will be deregulated by this date.

Gas from certain new onshore wells is to be deregulated by July 1987. Other categories of gas, except certain "high-cost" gas, will remain under price controls indefinitely. Between 1 July 1985 and 30 June 1987, the President (with congressional approval) or Congress may reimpose price controls for one 18 month period. Contract periods of up to 15 years for sales of new onshore natural gas may be established, and for high-cost gas or new gas produced from the Outer Continental Shelf, contract terms of at least 15 years are to be required. In addition, the original purchaser of gas under an expired contract and committed or dedicated to interstate commerce on the day before the NGPA was enacted may be given the right of first refusal to any subsequent sale of the gas.

Under the incremental pricing provision of the NGPA, interstate pipelines and distribution companies served by interstate pipelines must pass along the higher costs of certain new, high-cost, and imported natural gas to their large industrial customers who use gas for boiler fuel to generate steam or electricity. Under incremental pricing, industrial boiler

Table 3-11. DEREGULATION PROVISIONS IN THE NATURAL GAS POLICY ACT OF 1978

Category	Description	Price[a] ($/MM Btu)	Deregulation Date
New natural gas	New Outer Continental Shelf leases (on or after 20 April 1977)	2.10	1 January 1985
	New onshore wells	2.10	1 January 1985
	1) 2.5 miles or more from the nearest marker well		
	2) if closer than 2.5 miles to a marker well, and at least 1,000 ft deeper than the deepest marker well witnin 2.5 miles		
	New onshore reservoirs	2.10	1 January 1985
	Gas from reservoirs discovered after 27 August 1976 on old (pre 20 April 1977) Outer Continental Shelf leases	2.10	Not deregulated
New onshore production wells (If surface drilling began after 19 February 1977, and wells meet certain requirements as to spacing, production and conservation)	Gas produced from above 5,000-ft depth	1.98	1 July 1987
	Gas produced from below 5,000-ft	1.98	1 January 1985
High-cost gas	Production from below 15,000 ft from wells drilled after 19 February 1977	2.10	Deregulated on effective date of FERC incremental pricing rule called for by the act (within 1 year after enactment)
	Gas produced from geopressurized brine	Applicable rate under the act or higher incentive rate as set by FERC	
	Gas produced from coal seams		
	Gas produced from Devonian shale		
	Gas produced under other conditions that FERC judges to present "extraordinary risks or costs"		Not deregulated
Stripper-well gas (Natural gas—not produced in association with crude oil—that flows at an average rate not exceeding 60 Mcf/day)		2.24	
Gas committed to interstate commerce before the date of enactment (9 November 1978) (Classified by well-drilling date)	From wells started between 1 January 1975 and 18 February 1977	1.64	Not deregulated
	From wells started between 1 January 1973 and 3 December 1974		
	Small producer	1.39	
	Large producer	1.06	
	From wells started prior to 1 January 1973		
	Small producer	0.40	
	Large producer	0.33	
	Other gas (gas qualifying for special relief rates, etc.)	Applicable FERC rate	

Table 3-11. DEREGULATION PROVISIONS IN THE NATURAL GAS POLICY ACT OF 1978 (CONT'D)

Category	Description	Price[a] ($/MM Btu)	Deregulation Date
Gas committed to interstate commerce before the date of enactment (Classified by type of gas)	Replacement contract gas or recompletion gas		
	Small producer	0.78	Not deregulated
	Large producer	0.60	
	Certain Permian Basin gas		
	Small producer	0.47	
	Large producer	0.41	
	Certain Rocky Mountain gas		
	Small producer	0.47	
	Large producer	0.40	
	Certain Appalachian Basin gas		
	North subarea contacts dated after 7 October 1969	0.37	
	Other contracts	0.35	
	Minimum-rate gas—all producers	0.20	
Gas sold under existing intrastate contracts	If contract price is less than new natural gas price, it may escalate, as called for by contract, up to new natural gas price. If contract exceeds new natural gas price, then contract price plus annual inflation factor or new natural gas price plus escalation applies, whichever is higher.	Contract price	1 January 1985—if price exceeds $1.00 by 31 December 1984. If lower, not deregulated
Sales of gas made under "rollover" contracts (Expired contracts that have been renegotiated)	Interstate		
	Small producer	$0.72 or other applicable FERC rate	Not deregulated
	Large producer	$0.61 or other applicable FERC rate	Not deregulated
	Intrastate	The higher of expired contract price or $1.00	1 January 1985—if more than $1.00
Other categories	Natural gas produced from the Prudhoe Bay area of Alaska	$1.64 or other "just and reasonable" rate set by FERC	Not deregulated
	Any natural gas not covered under any other section of the bill		

[a]As of January 1979.

Source: *Federal Register,* Vol. 43, Part IV, 1 December 1978.

fuel users will bear the increment of gas costs above $1.48/million Btu (the March 1978 price, which will be adjusted each month for inflation), until the price to these users rises to the cost of fuel oil in the region. Only when the rates of all of an interstate pipeline's or distributor's industrial boiler fuel customers reach this level will its other customers, including residential and small commercial users, have to bear a portion of the higher gas costs. Institutions such as schools and hospitals, electric utilities, and certain industrial cogenerators of steam and electricity are exempted from incremental pricing rules. Small industrial boiler fuel facilities (using less than 300 Mcf/day) and agricultural users of natural gas (including food processors and fertilizer manufacturers) are exempted on an interim basis. Provisions are made for other exemptions in the future.

The President may declare a natural gas supply emergency if a gas shortage exists or is imminent, endangering supplies of gas for high-priority use—that is, any use of gas in a residence, a commercial establishment using less than 50 Mcf/day, schools and hospitals, or any use for which the curtailment of natural gas would endanger life, health, or the maintenance of physical property. During an emergency, the President may, under any contract terms and conditions he believes necessary, authorize interstate pipeline companies as well as distributors served by interstate pipelines to make emergency purchases of gas.

Curtailment provisions of the NGPA dictate that interstate gas supplies needed for certain essential agricultural and industrial uses generally will not be curtailed unless the gas is needed to serve high-priority customers. Rules are to be prescribed prohibiting interstate pipeline companies from curtailing essential agricultural uses (agricultural production, natural fiber production and processing, food quality maintenance, irrigation pumping, crop drying, or as a feedstock in making fertilizer, agricultural chemicals or animal feed) or essential industrial process and feedstock uses of gas, unless the gas would be needed to serve high-priority users or alternate fuels are reasonably available and economically practicable for these users.

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4. COAL

The United States has about 27 percent of the world's recoverable coal.[1] Statistics on U.S. coal are summarized in Table 4-1. Since the 1973 oil embargo by the Organization of Petroleum Exporting Countries (OPEC), the United States has increasingly emphasized the development of its abundant coal resources. Government legislation encourages the rapid expansion of coal production, and the substitution of coal for other energy sources has become a major U.S. policy objective. New technologies have been and are being developed to overcome the environmental and handling problems associated with coal production and use.

Table 4-1. COAL FACTS

Classification	Coals are classified as anthracite, bituminous, subbituminous, or lignite according to the amount of fixed carbon or calorific value (heat content)
Heat content	Lignite 12.6-16.6 million Btu/ton Subbituminous 16.6-23 million Btu/ton Bituminous 21-28 million Btu/ton Anthracite ≥ 25 million Btu/ton
Proved U.S. reserves, 1976	297 billion tons recoverable by underground mining methods 141 billion tons recoverable by surface mining methods 438 billion tons total
Estimated U.S. resources, 1974	1,734 billion tons mapped and explored 2,238 billion tons unmapped and explored 3,972 billion tons total
U.S. production, 1977[a]	689 million tons (56 percent surface mined)
Exports, 1977	53.7 million tons (including Canada)
Imports, 1977	1.8 million tons
U.S. consumption, 1977[a]	619.6 million tons
Contribution to demand	Coal supplied 19 percent of the 1976 U.S. energy demand

[a]Includes lignite.

Note: Data are in short tons.

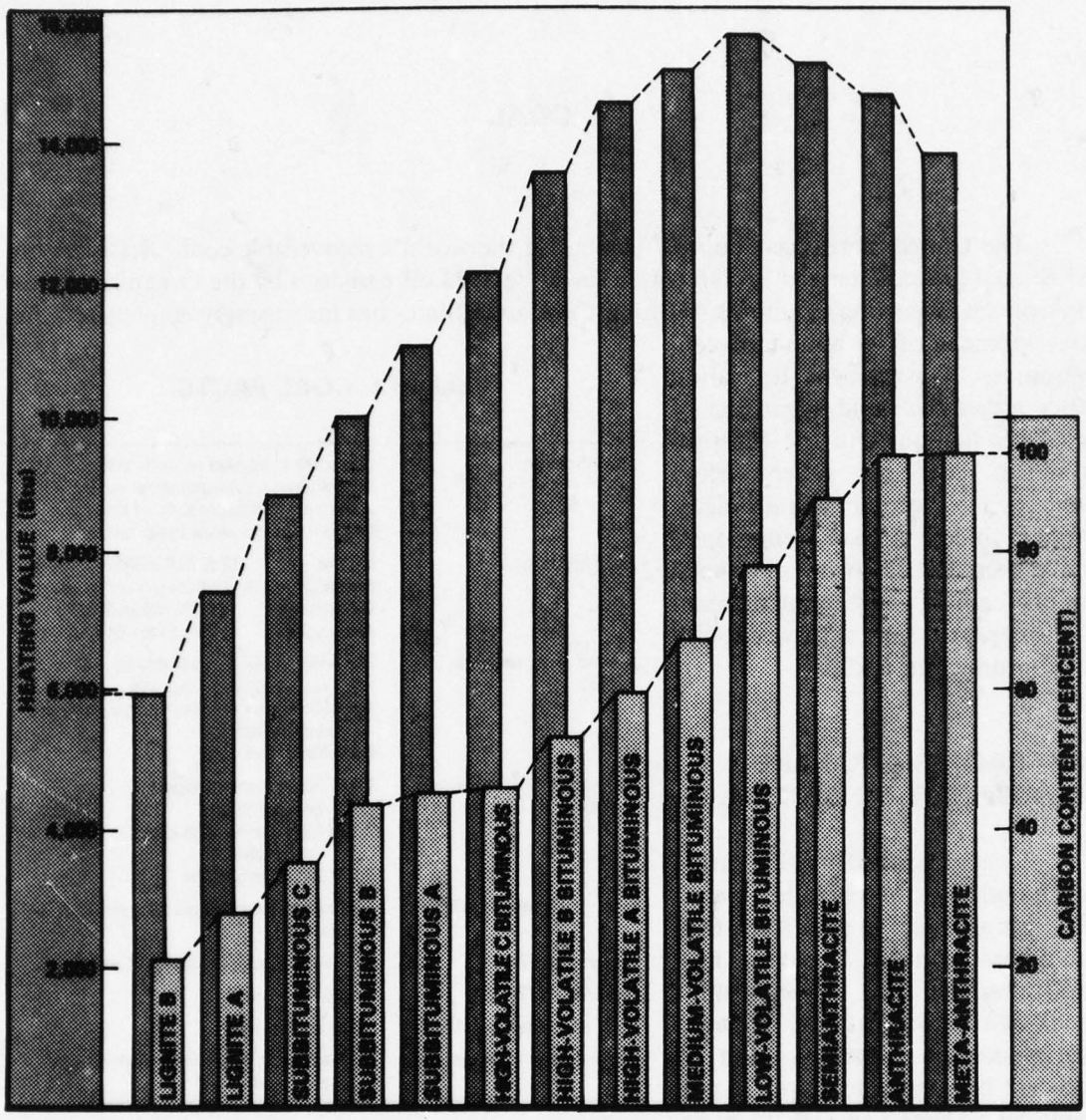
Sources: American Society for Testing Materials, "Standard Specification for Classification of Coals by Rank," ASTM Designation D388-66 (reapproved 1972), 1972 ASTM Standards—Part 19, pp. 54-58; U.S. Geological Survey, Bulletin 1412, 1975; and U.S. Department of the Interior, Bureau of Mines, "Demonstrated Coal Reserve Base of the United States, January 1, 1976" (August 1977), "Mineral Industry Surveys" (April 1978), and "Status of the Mineral Industries" (1977).

CHARACTERISTICS AND CLASSIFICATION OF COAL

Coal is formed by the partial decomposition of vegetable matter that accumulates in peat beds, then compresses under increased heat and pressure into a combustible rock-like material. Coal contains carbonaceous material—about 50 percent by weight and over 79 percent by volume—as well as moisture, ash, sulfur, and other impurities.[2]

Coal is classified by rank according to the degree of metamorphism, which is progressive from lignite to anthracite. The basic criteria used to rank coal are the carbon content and heating value. The percentages of fixed carbon and the heat content, except in anthracite, increase from the lowest to the highest rank of coal as the percentages of volatile matter and moisture decrease. The lower the rank of the coal, the lower the heating value, as shown in Figure 4-1. In the United States, the American Society for Testing Materials (ASTM) specifies the criteria for ranking coals.[2,3]

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Source: U.S. Geological Survey, "Coal Resources of the United States, January 1, 1974," Bulletin No. 1412, 1975.

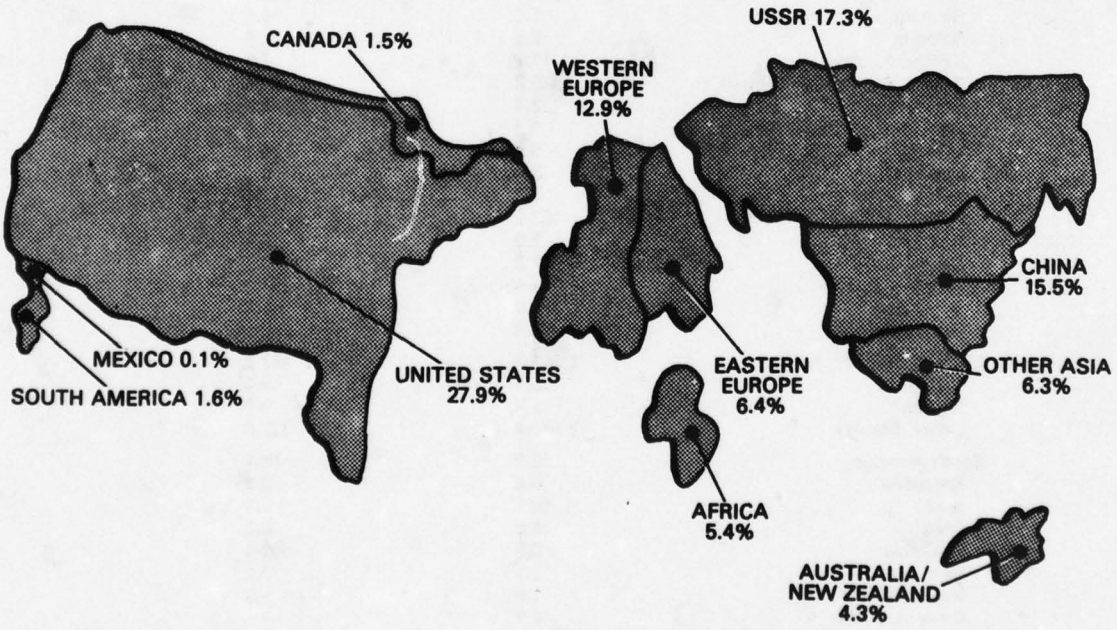
Figure 4-1. HEATING VALUE AND CARBON CONTENT OF COAL OF DIFFERENT RANKS

Coal is graded based on the impurities it contains, primarily ash and sulfur. Ash content, the amount of noncombustible inorganic material in coal, varies considerably by type of coal. Three forms of sulfur appear in coal: sulfur combined with iron as pyrite, organic sulfur, and sulfate sulfur (present only in trace amounts). About one-half of the sulfur in coal is pyritic. The total sulfur content of U.S. coals ranges from about 0.3 to 7.7 percent.[3] When coal is burned, the sulfur combines with oxygen to produce sulfur oxides (SO_x).

Coals are also categorized according to their caking properties—that is, their tendency to soften and agglomerate when heated and, after volatile matter has been driven off at high temperatures, to produce a hard gray cellular mass called coke. Noncaking or free-burning coals do not fuse together when heated, but tend to burn in separate pieces. Caking properties of a coal and the nature of the coke masses formed (such as size and strength) are valuable indicators of a fuel's performance in a furnace during direct combustion and in reactors to convert coal to liquid or gaseous fuels.

COAL AVAILABILITY AND UTILIZATION

Coal constitutes over 53 percent of the world's fossil energy resources. The bulk of the world's coal deposits are located in the industrialized countries (Figure 4-2). Coal resources in the United States alone total about 3.6 trillion metric tons (4 trillion short tons), according to a U.S. Geological Survey (USGS) estimate made in 1975. Known resources of bituminous coal, lignite, and anthracite in all other countries total about 7.6 trillion metric tons.[1] Only one-half of this coal is recoverable, however, because of losses in coal mining and processing. If only half of the coal reserves and resources is recovered, the amount of energy available from coal is still much greater than the total available from oil and gas. Table 4-2 lists world coal resources and reserves by country.



Note: Distortion of map reflects percentage of reserves. Total estimated at 701 billion short tons (approximately 4,662 billion barrels of oil equivalent).

Source: 1977 World Energy Conference.

Figure 4-2. WORLD RECOVERABLE COAL RESERVES

Table 4-2. WORLD COAL RESOURCES AND RESERVES[a]

Continent/Country	Geological Resources (10^9 t.c.e.[b])	Technically and Economically Recoverable Reserves (10^9 t.c.e)
Africa	172.9	34.1
Mozambique	0.4	0.1
Nigeria	0.2	0.1
Republic of Botswana	100.0	3.5
Republic of South Africa	57.6	26.9
Rhodesia	7.1	0.8
Swaziland	5.0	1.8
Zambia	0.2	—
Other countries	2.4	1.0
Asia	6,381.2	248.9
Bangladesh	1.6	0.5
India	56.8	33.7
Indonesia	3.7	1.4
Iran	0.4	0.2
Japan	8.6	1.0
North Korea	2.0	0.5
People's Republic of China	1,436.0	98.9
South Korea	0.9	0.4
Turkey	3.3	0.8
USSR	4,860.0	109.9
Other countries	5.7	1.6
Australia	262.9	27.5
Europe	590.9	128.0
Belgium	0.2	0.1
Bulgaria	2.6	2.2
Czechoslovakia	17.5	4.8
Federal Republic of Germany	246.8	34.4
France	2.4	0.4
German Democratic Republic	9.4	7.7
Greece	0.9	0.4
Hungary	3.6	0.9
Netherlands	2.9	1.4
Poland	125.5	21.0
Romania	1.8	0.4
Spain	2.3	0.5
United Kingdom	163.6	45.0
Yugoslavia	10.9	8.5
Other countries	0.4	0.1
North America	2,891.2	187.8
Canada	115.4	9.4
Mexico	5.4	0.9
United States	2,570.4	177.6
South America	26.2	10.1
Argentina	0.4	0.3
Brazil	10.1	8.1
Chile	4.6	0.2
Columbia	8.3	0.4
Peru	1.1	0.1
Venezuela	1.6	0.9
Other countries	0.1	—
Total world	10,125.3	636.4

[a]Includes anthracite, bituminous and subbituminous coal, and lignite.

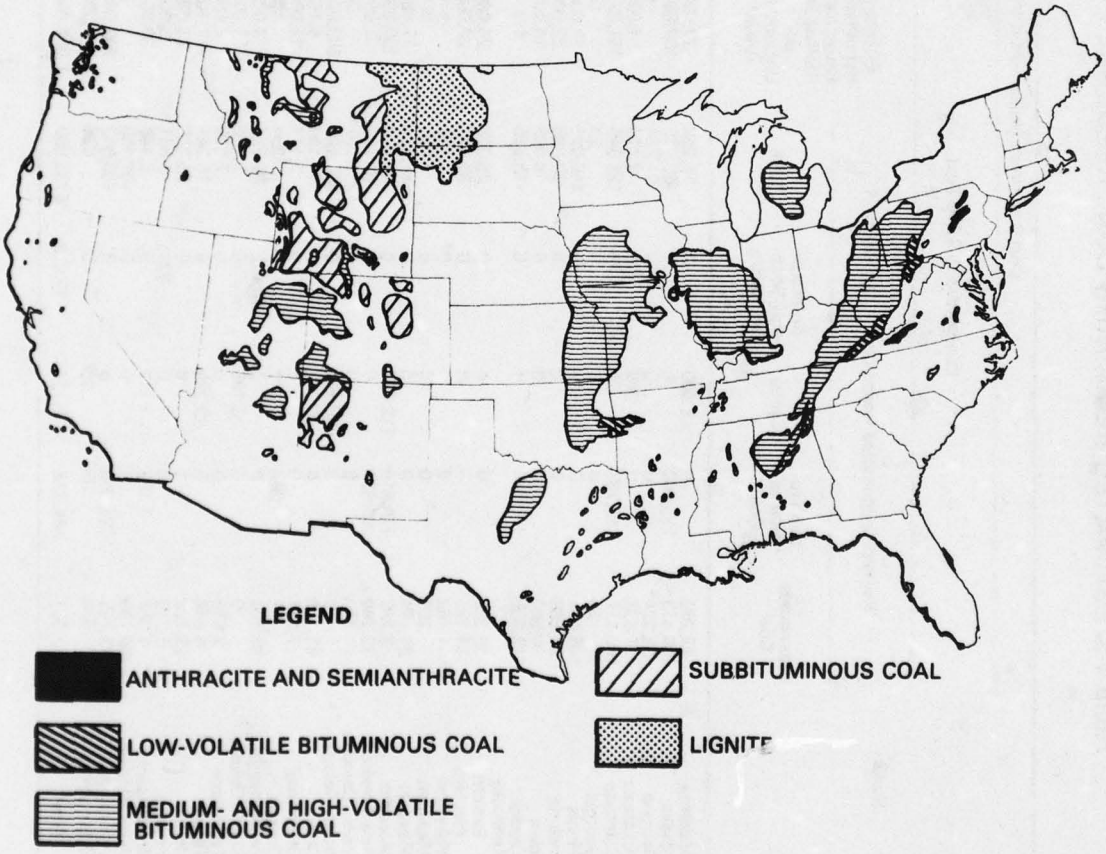
[b]One ton coal equivalent (t.c.e.) corresponds to the average calorific value of 1 metric ton of hard coal; 1 t.c.e. = 27.78×10^6 Btu.

Source: World Energy Conference, *World Energy Resources, 1985-2020* (New York: IPC Science and Technology Press, 1978).

U.S. Coal Resources

Coal fields of the contiguous United States and Alaska are shown in Figures 4-3 and 4-4. The most recent government estimates for U.S. coal resources in-place are presented in Table 4-3. (Official coal resource estimates are made by USGS, while the Bureau of Mines (BOM) reports coal reserve data.) There are several categories of estimates. "Remaining identified resources" are based on factual information and are further divided into:

- Measured resources, which are based on assumed coal-bed correlations and closely spaced observations (about 1 km apart).
- Indicated resources, which are based partly on specific observations and partly on reasonable geologic projections. The points of observation and measurement are about 1.6 km apart for beds of known continuity.
- Inferred resources, which are based on an assumed continuity of coal beds adjoining and dipping down from areas containing measured and indicated resources.



Source: U.S. Geological Survey, "Coal Resources of the United States, January 1, 1974," Bulletin No. 1412, 1975.

Figure 4-3. COAL FIELDS OF THE CONTIGUOUS UNITED STATES

Table 4-3. ESTIMATED REMAINING COAL RESOURCES OF THE UNITED STATES

State	Coal Resources (million short tons)								
	Overburden 0-3,000 Feet							Overburden 3,000-6,000 Feet	Overburden 0-6,000 Feet
	Remaining Identified Resources, 1 January 1974					Estimated Hypothetical Resources in Unmapped and Unexplored Areas[a]	Estimated Total Identified and Hypothetical Resources Remaining in the Ground	Estimated Additional Hypothetical Resources in Deeper Structural Basins[a]	Estimated Total Identified and Hypothetical Resources Remaining in the Ground
	Bituminous Coal	Subbituminous Coal	Lignite	Anthracite and Semianthracite	Total				
Alabama	13,262	0	2,000	0	15,262	20,000	35,262	6,000	41,262
Alaska	19,413	110,666	b	c	130,079	130,000	260,079	5,000	265,079
Arizona	21,234[d]	d	0	0	21,234	0	21,234	0	21,234
Arkansas	1,638	0	350	428	2,416	4,000[e]	6,416	0	6,416
Colorado	109,117	19,733	20	78	128,948	161,272	290,220	143,991	434,211
Georgia	24	0	0	0	24	60	84	0	84
Illinois	146,001	0	0	0	146,001	10,000	246,001	0	246,001
Indiana	32,868	0	0	0	32,868	22,000	54,868	0	54,868
Iowa	6,505	0	0	0	6,505	14,000	20,505	0	20,505
Kansas	18,668	0	f	0	18,668	4,000	22,668	0	22,668
Kentucky									
Eastern	28,226	0	0	0	28,226	24,000	52,226	0	52,226
Western	36,120	0	0	0	36,120	28,000	64,120	0	64,120
Maryland	1,152	0	0	0	1,152	400	1,552	0	1,552
Michigan	205	0	0	0	205	500	705	0	705
Missouri	31,184	0	0	0	31,184	17,489	48,673	0	48,673
Montana	2,299	176,819	112,521	0	291,639	180,000	471,639	0	471,639
New Mexico	10,748	50,639	0	4	61,391	65,556[g]	126,947	74,000	200,947
North Carolina	110	0	0	0	110	20	130	5	135
North Dakota	0	0	350,602	0	350,602	180,000	530,602	0	530,602
Ohio	41,166	0	0	0	41,166	6,152	47,318	0	47,318
Oklahoma	7,117	0	f	0	7,117	15,000	22,117	5,000[h]	27,117
Oregon	50	284	0	0	334	100	434	0	434
Pennsylvania	63,940	0	0	18,812	82,752	4,000[i]	86,752	3,600[j]	90,352
South Dakota	0	0	2,185	0	2,185	1,000	3,185	0	3,185
Tennessee	2,530	0	0	0	2,530	2,000	4,530	0	4,530
Texas	6,048	0	10,293	0	16,341	112,100[k]	128,441	k	128,441
Utah	23,186[l]	173	0	0	23,359	22,000[m]	45,359	35,000	80,359
Virginia	9,216	0	0	335	9,551	5,000	14,551	100	14,651
Washington	1,867	4,180	117	5	6,169	30,000	36,169	15,000	51,169
West Virginia	100,150	0	0	0	100,150	0	100,150	0	100,150
Wyoming	12,703	123,240	b	0	135,943	700,000	835,943	100,000	935,943
Other states[n]	610	32[o]	46[p]	0	688	1,000	1,688	0	1,688
Total	747,357	485,766	478,134	19,662	1,735,000	1,849,649	3,580,568	387,696	3,972,000[q]

Note: Estimates include beds of bituminous coal and anthracite generally 14 inches or more thick, and beds of subbituminous coal and lignite generally 2½ feet or more thick, to overburden depths of 3,000 and 6,000 feet. Figures are for resources in the ground.

[a]Source of estimates: Alabama, W. C. Culbertson; Arkansas, B. R. Haley; Colorado, Holt (1975); Illinois, M. E. Hopkins and J. A. Simon; Indiana, C. E. Wier; Iowa, E. R. Landis; Kentucky, K. J. Englund; Missouri, Robertson (1971, 1973); Montana, R. E. Matson; New Mexico; Fassett and Hinds (1971); North Dakota, R. A. Brant; Ohio, H. R. Collins and D. O. Johnson from data in Struble and others (1971); Oklahoma, S. A. Friedman; Oregon, R. S. Mason; Pennsylvania anthracite, Arndt and others (1968); Pennsylvania bituminous coal, W. E. Edmunds; Tennessee, E. T. Luther; Texas lignite, Kaiser (1974); Virginia, K. J. Englund; Utah, H. H. Doelling; Washington, H. M. Beikman; Wyoming, N. M. Denson, G. B. Glass, W. R. Keefer, and E. M. Schell; remaining states, by P. Averitt.

[b]Small resources of lignite included under subbituminous coal.

[c]Small resources of anthracite in the Bering River field believed to be too badly crushed and faulted to be economically recoverable (Barnes, 1951).

[d]All tonnage is in the Black Mesa field. Some coal in the Dakota Formation is near the rank boundary between bituminous and subbituminous coal. Does not include small resources of thin and impure coal in the Deer Creek and Pinedale fields.

[e]Lignite.

[f]Small resources of lignite in western Kansas and western Oklahoma in beds generally less than 30 inches thick.

[g]After Fassett and Hinds (1971), who reported 85,222 million tons "inferred by zone" to an overburden depth of 3,000 feet in the Fruitland Formation of the San Juan basin. Their figure has been reduced by 19,666 million tons as reported by Read and others (1950) for coal in all categories also to an overburden depth of 3,000 feet in the Fruitland Formation of the San Juan basin. The figure of Read and others was based on measured surface sections.

[h]Includes 100 million tons inferred below 3,000 feet.

[i]Bituminous coal.

[j]Anthracite.

[k]Lignite, overburden 200–5,000 feet; identified and hypothetical resources undifferentiated. All beds assumed to be 2 feet thick, although many are thicker.

[l]Excludes coal in beds less than 4 feet thick.

[m]Includes coal in beds 14 inches or more thick, of which 15,000 million tons is in beds 4 feet or more thick.

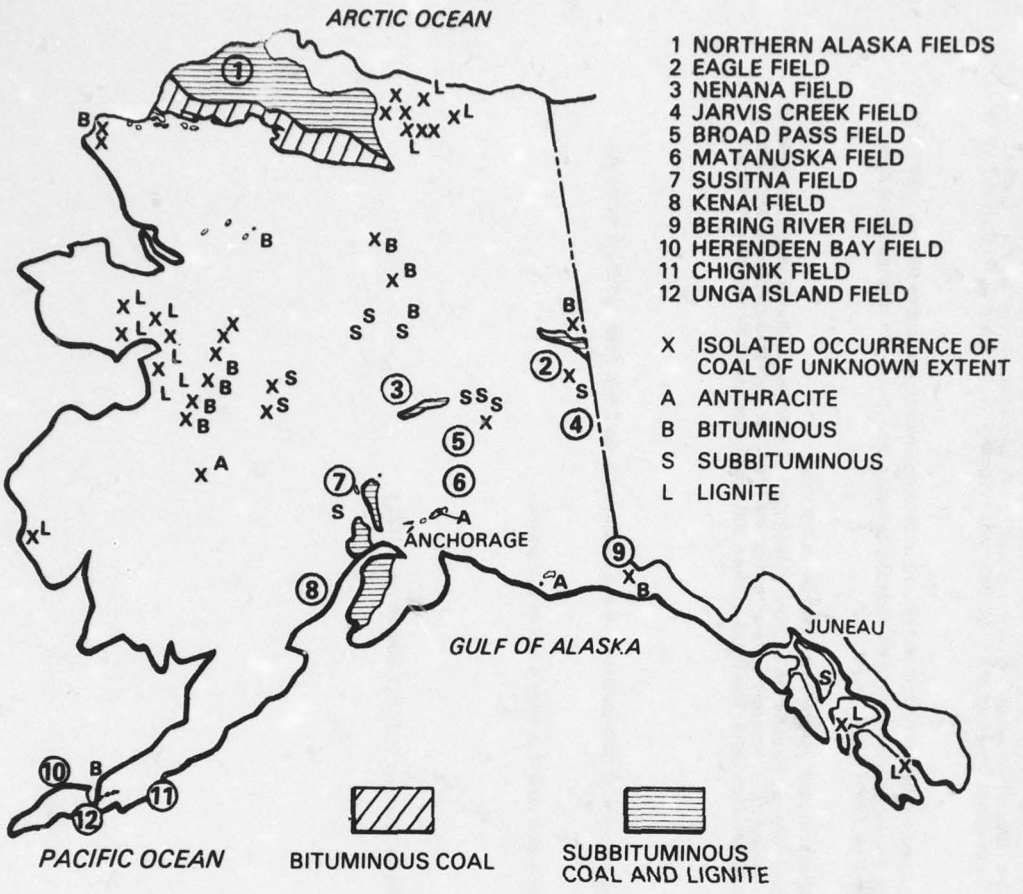
[n]California, Idaho, Nebraska, and Nevada.

[o]California and Idaho.

[p]California, Idaho, Louisiana, and Mississippi.

[q]Four million short tons located not previously reported.

Source: U.S. Geological Survey, "Coal Sources of the United States, January 1, 1974," Bulletin No. 1412.



Source: U.S. Geological Survey, "Coal Resources of the United States, January 1, 1974," Bulletin No. 1412, 1975.

Figure 4-4. COAL FIELDS OF ALASKA

"Hypothetical resources" shown on Table 4-3 are estimates of coal in-place in unmapped and unexplored parts of known coal basins to an overburden depth of 1,800 m (6,000 ft). These estimates are determined by extrapolation from nearby areas of identified resources.

The demonstrated coal reserve base shown in Table 4-4 is the sum of the measured and indicated resource categories. This demonstrated reserve base is restricted primarily to coal in thick and intermediate beds that are less than 300 m below the surface and are deemed to be economically and legally available for mining.

Approximately 44 percent of the total estimated remaining coal resources in the United States have been identified. At least 12.5 percent of these resources is considered economically recoverable, based on past recovery rates. Of the total identified resources, about 43 percent is bituminous coal, 91 percent is 300 m or less below the surface, and 33 percent is in thick beds. Remaining identified resources in the northern Great Plains and

Table 4-4. DEMONSTRATED U.S. COAL RESERVE BASE, 1 JANUARY 1976[a]
(Millions of short tons)

State	Coal Potentially Minable by Surface Methods					Coal Potentially Minable by Underground Methods[b]			
	Anthracite	Bituminous	Subbituminous	Lignite	Total	Anthracite	Bituminous	Subbituminous	Total
Alabama	–	284.4	–	1,083.0	1,367.4	–	1,724.2	–	1,724.2
Alaska	–	80.5	640.7	14.0	735.2	–	617.0	4,805.9	5,423.0
Arizona	–	325.5	–	–	325.5	–	–	–	–
Arkansas	7.8	107.0	–	25.7	140.5	88.6	163.1	–	251.7
Colorado	–	676.2	149.2	2,965.7	3,791.0	25.5	8,467.9	3,972.1	12,465.4
Georgia	–	0.4	–	–	0.4	–	0.5	–	0.5
Illinois	–	14,841.2	–	–	14,841.2	–	53,128.1	–	53,128.1
Indiana	–	1,774.5	–	–	1,774.5	–	8,939.8	–	8,939.8
Idaho	–	–	–	–	–	–	4.4	–	4.4
Iowa	–	465.4	–	–	465.4	–	1,736.8	–	1,736.8
Kansas	–	998.2	–	–	998.2	–	–	–	–
Kentucky, East	–	4,467.6	–	–	4,467.6	–	9,072.5	–	9,072.5
Kentucky, West	–	3,950.4	–	–	3,950.4	–	8,510.4	–	8,510.4
Louisiana	–	–	–	b	b	–	–	–	–
Maryland	–	134.5	–	–	134.5	–	913.8	–	913.8
Michigan	–	1.6	–	–	1.6	–	125.2	–	125.2
Missouri	–	3,596.0	–	–	3,596.0	–	1,418.0	–	1,418.0
Montana	–	–	33,843.2	15,766.8	49,610.1	–	1,385.4	69,573.5	70,958.9
New Mexico	–	601.1	1,846.8	–	2,447.9	2.3	1,258.8	889.0	2,150.1
North Carolina	–	0.4	–	–	0.4	–	31.3	–	31.3
North Dakota	–	–	–	10,145.3	10,145.3	–	–	–	–
Ohio	–	6,139.8	–	–	6,139.8	–	13,090.5	–	13,090.5
Oklahoma	–	425.2	–	–	425.2	–	1,192.9	–	1,192.9
Oregon	–	–	2.9	–	2.9	–	b	14.5	14.5
Pennsylvania	142.7	1,391.8	–	–	1,534.4	6,966.8	22,335.9	–	29,302.7
South Dakota	–	–	–	426.1	426.1	–	–	–	–
Tennessee	–	337.9	–	–	337.9	–	627.2	–	627.2
Texas	–	–	–	3,181.9	3,181.9	–	–	–	–
Utah	–	267.9	–	–	267.9	–	6,283.8	1.1	6,284.9
Virginia	–	888.5	–	–	888.5	137.5	3,277.0	–	3,414.5
Washington	–	–	481.5	8.1	489.5	–	255.3	835.3	1,090.6
West Virginia	–	5,149.1	–	–	5,149.1	–	33,457.4	–	33,457.4
Wyoming	–	–	23,724.7	–	23,724.7	–	4,002.5	27,644.8	31,647.2
Total	150.5	46,905.0	60,688.9	33,616.6	141,361.0	7,220.7	182,019.6	107,736.1	296,976.3

[a]Includes measured and indicated resource categories as defined by BOM and USGS and represents 100 percent of the coal in place. Data may not add to totals shown due to rounding.

[b]Quantity undetermined (basic resource data do not provide the detail required for delineation of reserve base).

Source: U.S. Department of the Interior, Bureau of Mines, "Mineral Industry Surveys," August 1977.

Rocky Mountain area constitute about two-thirds of the nation's remaining identified resources. While most of this western coal has low sulfur content (under 2 percent) and is amenable to surface mining, it also usually has lower heat content than eastern and central U.S. coals; about 72 percent of western coal is subbituminous.

Production and Consumption in the United States

Coal production and consumption statistics for the United States are presented in Table 4-5 and Figure 4-5. Production of lignite and bituminous coal reached nearly 616 million metric tons (679 million short tons) in 1976, and an estimated 625 million metric tons (689 million short tons) in 1977. During the first 4 months of 1978, about 118 million metric tons (130 million short tons) were produced, a 36.2 percent decrease from production during the first 4 months of 1977.[4] Six states (Illinois, Kentucky, Ohio, Pennsylvania, Virginia, and West Virginia) accounted for almost three-fourths of the coal mined.[5]

Productivity in surface mines decreased from about 33 metric tons/man-day (36.7 short tons) in 1973 to 24 metric tons/man-day (26.4 short tons) in 1976. Reasons for the drop in productivity in recent years include more difficult conditions in some mines (such as smaller coal seams and longer distances from mine entrances to the operating faces), increases in exploration activity (as opposed to direct production), wildcat strikes, and absenteeism. Also, the 1969 Federal Coal Mine Health and Safety Act, which mandated safety activities that required additional manpower and increased outlays in safety equipment, has been a major cause of decreased productivity in underground mines since 1969.

Of the coal available in the United States for consumption in 1977, about 74 percent (431 million metric tons) was used by the electric utility industry (compared to 62 percent in 1970 and about 50 percent in 1963). Coke was the second most important end use, consuming about 70 million metric tons of the coal produced. U.S. coke imports increased significantly from about 1.6 million metric tons in 1977 to about 5.2 million metric tons in 1978. All other uses, including beehive coke plants, steel and rolling mills, sales by retail dealers, and other manufacturing and mining industries, accounted for only 12 percent of total coal consumption.[4]

Projections

Supply and demand projections for coal vary. The U.S. Department of Energy (DOE) estimated (after the National Energy Act passed) that coal production will range from 916 million to 980 million metric tons in 1985.[6] (DOE's estimates were based on oil prices of $14.50 and $19.72/bbl respectively.) The U.S. General Accounting Office (GAO) estimates that actual demand by 1985 will range from 707 million metric tons (based on the Edison Electric Institute's low-growth scenario[7]) to 896 million metric tons (based on BOM's high growth scenario[8]). According to GAO, reaching these levels would require:

- Opening 438 to 825 new mines, adding 288,300 to 531,600 miners.
- Manufacturing large quantities of mining equipment.
- Investing $26.7 billion to $45.5 billion in capital.
- Improving mining health and safety conditions and increasing productivity.

Table 4-5. COAL PRODUCTION AND CONSUMPTION STATISTICS

Item	1973	1974	1975	1976	1977 (Preliminary)[a]
Lignite and Bituminous Coal					
Production (thousands of short tons)	591,738	603,406	648,438	678,685	688,575
Value (thousands)	$5,049,612	$9,502,347	$12,472,486	$13,189,481	$14,115,768
Consumption (thousands of short tons)	556,022	552,709	556,301	598,750	619,616
Stocks at end of year					
Industrial consumers and retail years (thousands of short tons)	103,022	95,528	127,115	133,555	152,317
Stocks on upper lake docks (thousands of short tons)	822	1,051	1,185	835	738
Exports[b] (thousands of short tons)	52,870	59,926	65,689	59,406	53,687
Imports[b] (thousands of short tons)	127	2,080	940	1,203	1,803
Price indicators, average per net ton					
Cost of coking coal at merchant coke ovens	$19.77	$34.20	$52.63	$54.90	$55.50
Railroad freight charge[c]	$3.71	$4.71	$5.23	$5.86	$6.51
Value FOB mines	$8.53	$15.75	$19.23	$19.43	$20.50
Method of mining					
Underground—total (thousands of short tons)	299,353	277,309	292,826	294,880	271,630
Percentage mined by underground methods	50.6	46.0	45.2	43.4	39.4
Surface—total (thousands of short tons)	292,384	326,097	355,612	383,805	416,945
Percentage mined by surface methods	49.4	54.0	54.8	56.6	60.6
Number of mines	4,744	5,247	6,168	6,161	6,200
Coke					
Production					
Oven coke (thousands of short tons)	63,496	60,737	56,494	57,728	
Beehive coke (thousands of short tons)	829	845	713	605	
Total (thousands of short tons)	64,325	61,581	57,207	58,333	
Exports (thousands of short tons)	1,395	1,278	1,273	1,315	
Imports (thousands of short tons)	1,094	3,540	1,819	1,311	
Producers' stocks, December 31 (thousands of short tons)	1,184	935	5,001	6,491	
Consumption, apparent (thousands of short tons)	65,765	64,092	53,687	56,834	
Value of coal-chemical materials used or sold (thousands)	$355,667	$652,735	$653,958	$919,834	
Value of coke and breeze used or sold (thousands)	$2,575,150	$4,609,209	$4,607,292	$5,020,857	
Total value of all products used or sold[d] (thousands)	$2,930,817	$5,261,944	$5,261,250	$5,940,691	

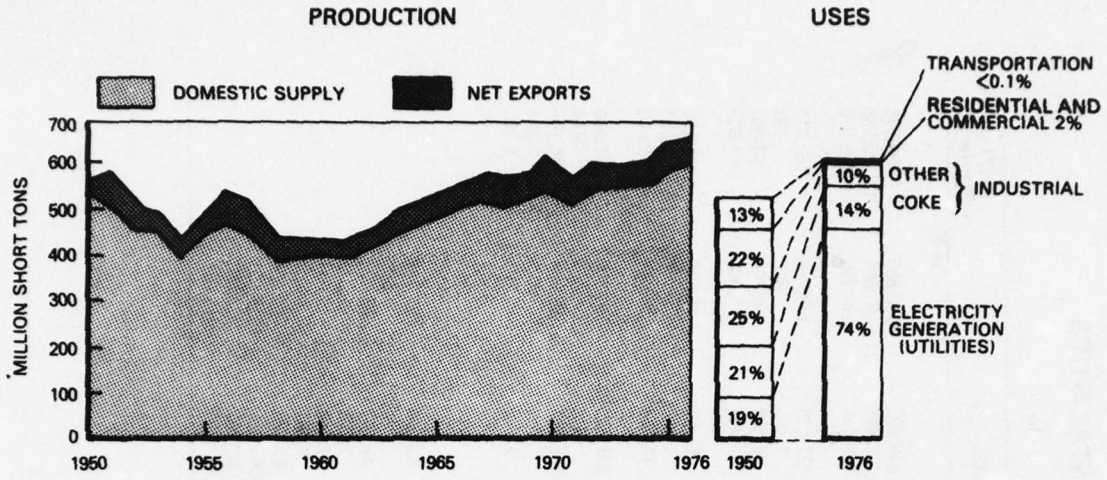
[a]Subject to revision upon completion of annual canvass; data for coke not available.

[b]U.S. Department of Commerce, Bureau of the Census.

[c]Interstate Commerce Commission.

[d]Data may not add to totals shown because of independent rounding.

Source: U.S. Department of Energy, "Energy Data Reports," *Weekly Coal Reporter,* 28 April 1978.



Source: Exxon Company, U.S.A., *Energy Outlook, 1978-1990,* May 1978.

Figure 4-5. U.S. PRODUCTION AND USES OF COAL

The additional manpower and equipment required may impose limits on the future supply of coal. Transportation requirements also pose problems in attaining projected supply goals. The physical congestion of key rail lines (particularly in the west) and the poor condition of many railroad beds (especially in the northeast) will need to be resolved. Substantial amounts of capital will be required to restore and upgrade rail facilities, as well as to improve the inland waterway system.

A 1976 BOM study assessed the economic health of the coal industry to determine its ability to obtain the capital required for increased coal supplies. The report, based on a detailed analysis of the financial performance and corporate structure of 30 selected coal firms responsible for about 60 percent of the 1974 national coal production, concluded that the trends toward increased size of coal companies and their absorption by mineral and energy companies might strengthen the financial position of the coal industry. A parent or controlling company with a coal subsidiary or affiliate can shift capital funds in accordance with program needs, and can more easily approach the money market for new capital than can the average coal company.[9] The trend toward fewer and larger coal companies is expected to increase because of the large amounts of capital needed for opening and expanding mines and meeting environmental, health, and safety standards.

PRODUCTION TECHNOLOGY

Exploration

Because the locations of most coal fields in the United States are generally well-known and well-mapped, exploration methods have not changed significantly in recent years. The steps involved in conventional coal exploration are:

- Compilation of existing geological, geochemical, and geophysical data for the area and determination of current ownership and surface and mineral rights.
- Sampling and study of suspected or identified deposits, including core drilling and analysis to determine data such as seam thickness, depth, and areal extent. While core drilling is the most common method, geophysical hole-logging methods, also are used.

Large bulk samples are sometimes taken for washability tests to determine design parameters for preparation plants, coking tests, and other process testing.[2]

Other techniques include:

- Geophysical methods such as magnetic, gravimetric, and seismic surveys to infer variations of geologic structure and stratigraphy.[10]
- Surface geologic mapping and geophotographic analysis using aerial photographic and Landsat imagery.

The results of the sampling, measurements, and surveys undertaken during exploration are used in mapping coal areas. Further, the results of the analyses performed are useful in determining the amount of cleaning required before the coal can be used, as well as the best end use for the coal (such as conversion, coke production, or direct combustion).

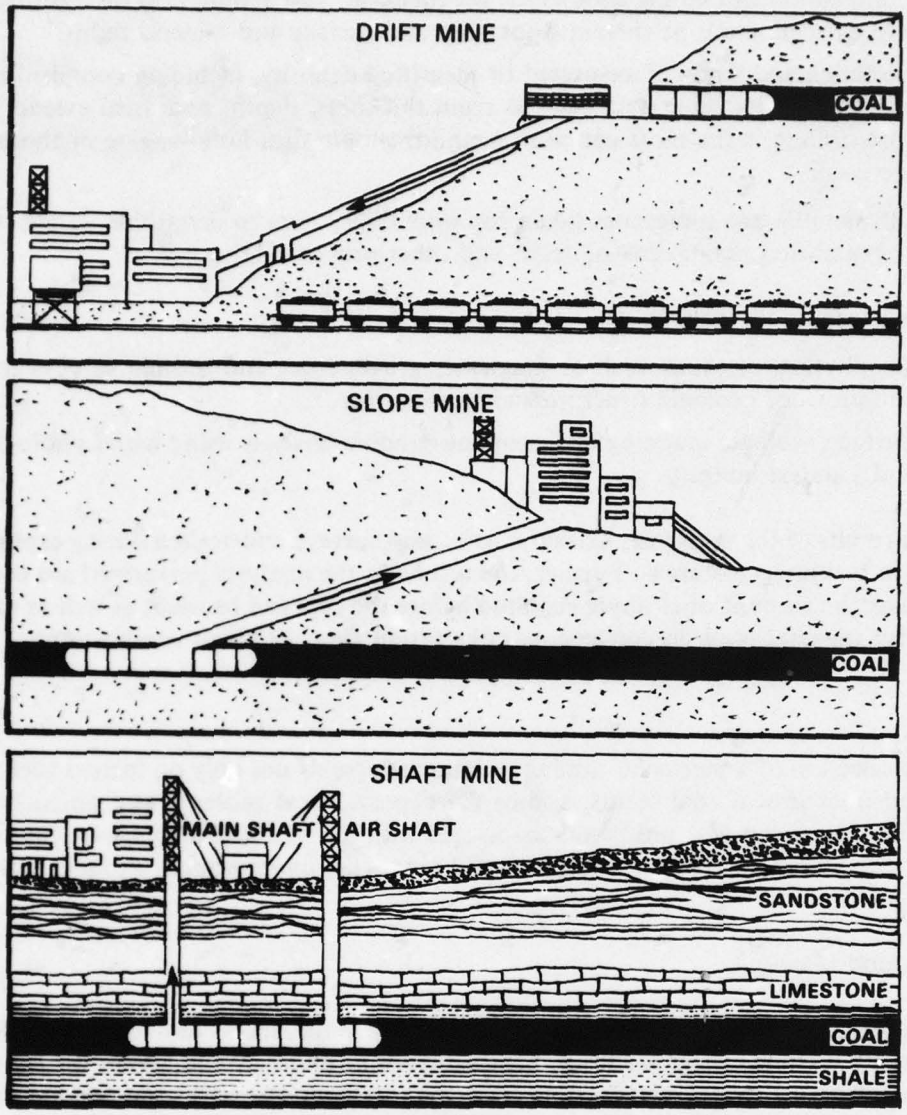
Mining

The selection of a particular mining technique depends not only on factors such as the depth and thickness of coal seams, size of the deposit, local geology, and potential environmental effects, but also on factors associated with the cost and manpower required for maximum productivity. The most common techniques are underground, surface, and auger mining.

Underground Mining

Underground mining is used when the coal is buried too deeply to make surface mining economically feasible. There are three different types of underground mines, differentiated by the method used to make an opening from the surface to the coal seam (see Figure 4-6). Drift mines have an opening directly into a horizontal coal seam outcropping on the side of a hill or mountain. Since little excavation is required, drift mines are usually the least expensive underground mines to open. Slope mines have inclined openings that either follow the slope of the coal bed or pass through layers of rock overlaying the coal. Slopes extend to greater depths as improved rock tunneling machines are developed. In shaft mines, the openings are vertical from the surface to the coal seams. Shaft mines usually are developed where the coal seams are under deep cover. These three kinds of openings can be used in any combination as required for specific mining areas.

Three general methods of underground mining are room-and-pillar, longwall, and shortwall. In room-and-pillar mining, part of the coal is removed by excavating intersecting tunnels. Between the tunnels, large blocks of coal, or pillars, are left standing to support the mine roof. The pillars are sometimes removed (when no longer needed) to recover additional coal. As much as 50 to 60 percent of the coal can be recovered using this system.[3]



Source: National Coal Association, *Coal Facts, 1978-1979.*

Figure 4-6. UNDERGROUND MINES

Room-and-pillar mines may employ either conventional or continuous mining technology. Conventional mining accounts for about 32 percent of all coal mined underground in the United States.[11] A cutting machine, similar to a large chain saw, cuts a deep slot into the coal. Holes are drilled, into which spark-proof explosives or cylinders of compressed air are inserted to shatter the coal. The coal then is gathered and transported using special equipment, such as mobile conveyor belts or shuttle cars (low-slung electric cars). Finally, roof supports are installed and ventilation is extended. In contrast to conventional mining where several machines are used to cut and load the coal, continuous mining employs one machine to break the coal mechanically and load it for transport. Roof supports are in-

stalled and ventilation is extended as with conventional mining. About 63 percent of all U.S. coal mined underground is produced with continuous mining equipment.[11] Continuous mining is less labor-intensive than conventional mining.

In the longwall mining system, large blocks of coal are extracted in a single, continuous operation. A shearing drum moves back and forth across the working face of the coal seam, and the loosened coal falls onto a conveyor. Self-advancing hydraulic-yielding jacks support the roof at the immediate face as the coal is removed, and as the face is advanced, the strata are allowed to cave in behind the support units. Longwall mining, although used extensively in Europe, accounts for only about 4 percent of U.S. coal mined underground.[12] Longwall mining is less labor-intensive than the room-and-pillar system, the recovery percentage of the coal in-place is higher, and electricity consumption is lower. Although the capital costs for longwall mining systems are up to five times those for conventional or continuous mining, the industry's interest in this system is increasing. DOE is supporting research to improve longwall system performance and decrease system costs. Nevertheless, this method requires large uniform blocks of coal, and cannot be used for steeply pitched seams, or for seams less than 56 cm or more than 3 m thick.[13]

The relatively new shortwall technique combines the room-and-pillar and longwall systems. Shortwall mining may be applied where the seam face is substantially shorter than the 183 m length typical for longwall mining, and where the roof is easily crumbled or pulverized.[11] Continuous or conventional mining equipment is used to develop the field, and the remaining coal pillars are extracted using a continuous miner in conjunction with the longwall-type roof supports. Overall recovery can be up to 85 percent of the coal in the seam.[11] As with longwall mining, increased productivity and fewer accidents and fatalities are other advantages of shortwall mining.

Surface Mining

Surface mining often is used to recover coal that cannot be extracted by underground methods due to thinness of coal bed, proximity of multiple beds, split seams, nature of the roof, or other geologic conditions. Surface mining is used also to recover coal from seams very close to the surface, as in the western United States. Because of advances in mining technology and equipment, surface mine production now accounts for about half of total U.S. coal production. The decision to use surface mining methods is heavily dependent on the ratio of overburden thickness to seam thickness when weighed against the price of the coal. DOE classifies coals under 38 m or less of overburden as economically minable from the surface.[14] Recoverability by surface mining averages 80 to 90 percent.[3]

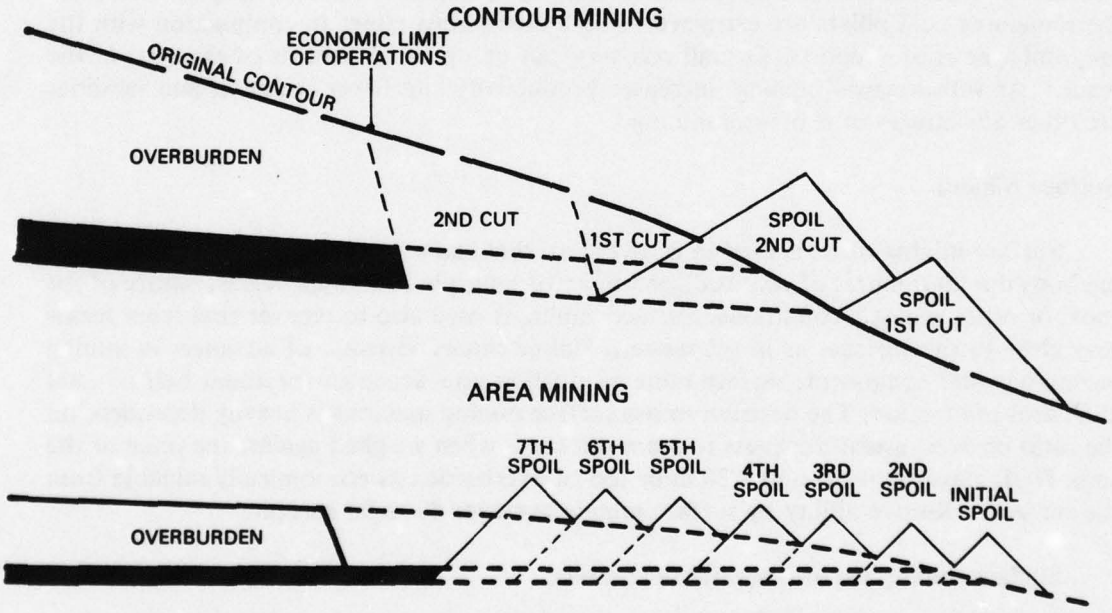
Surface mining requires several operations:

- Surface preparation—Building roads and necessary facilities, removing vegetation, and hauling and stockpiling topsoil for replacement during reclamation.
- Fracturing—Drilling blastholes through the overburden to the coal seam, followed by blasting to break up the overburden.
- Excavation—Removing overburden and coal.
- Hauling—Transporting coal out of the pit.

- Reclamation—Smoothing out piles of overburden, replacing topsoil, and revegetating the area.

Two major types of surface mining used in the United States are area mining and contour mining (see Figure 4-7). Area mining is used in flat terrain. Conventional dragline or shovel methods are used to excavate a sequence of parallel pits, and the overburden, which is removed as the coal is mined, is spilled into the previous pit. Where the coal seams are very thick (12 to 30 m), the coal is mined in open-pit fashion.[15] In this case, since the loading equipment works on the floor of the mine from which the coal has just been removed, the previous mined-out area cannot be filled with removed overburden; thus, the overburden must be transported elsewhere.

Contour mining is used in hilly or mountainous terrain. Beginning at a place where the coal and surface elevations are the same, the overburden is removed with draglines, scrapers, or bulldozers and cast downhill. The exposed coal is loaded into trucks and removed from the pit. A second pit is excavated and its overburden placed in the first pit. This sequence is continued until the maximum (economic) depth limit of the overburden is reached. If large enough quantities of coal remain but the seam is too thin to justify underground mining, augers can be used to extract the coal horizontally.



Source: Edwin R. Phelps, "Modern Mining Methods," *Elements of Practical Coal Mining*, Samuel M. Cassidy, ed. (New York: American Institute of Mining, Metallurgical and Petroleum Engineers, Inc., 1973).

Figure 4-7. SURFACE MINES

Auger Mining

Auger mining is applied where the overburden is too thick to be removed economically by ordinary surface mining methods, and underground mining is infeasible. The technology involves drilling large diameter, spaced holes to penetrate up to 61 m into the coal bed. Drilling is done by an auger consisting of a cutting head with screwlike extensions. As the auger turns, the head breaks the coal; the screw carries it back above the ground and dumps it on a conveyor. The average recovery of coal by auger mining is low (35 percent).[15]

Coal Beneficiation

Before coal can be used in most combustion and conversion processes, it must be sized and cleaned—beneficiated—to alter the sulfur, ash, and moisture content as well as to remove extraneous materials that are introduced during mining (such as equipment parts, pieces of wood, explosives and caps, and rock dust). Sand, gravel, gypsum, coke, and other materials that are introduced when the coal is transported also must be removed. The basic steps in conventional coal beneficiation are (1) size reduction by crushing, using large rotary mills and screens to separate particles of different sizes; (2) mechanical and/or chemical cleaning to remove dust and impurities; and (3) drying before shipping or use. Between 60 to 90 percent of pyritic sulfur (40 to 70 percent of the total sulfur) in raw coal can be removed by conventional methods. Organic sulfur cannot be removed by washing, although the sulfur oxides produced during combustion can be removed from flue gases (see Environmental Aspects).

Conventional cleaning may be performed by air washing or wet washing. In the former, small particles are removed by blowing air over the coal. Wet washing can be accomplished by:

- Floating the coal on a water/magnetite (pulverized iron ore) slurry until the impurities sink. Coal has a lower specific gravity than the impurities; thus, the impurities separate and settle faster than the coal.
- Entraining the coal in an upward flow of water.
- Mixing the coal in water with flotation agents, which cause the coal to repel water, and passing air bubbles, which adhere to the coal particles, through the mixture. The air bubbles do not adhere to the impurities, which are allowed to sink. The coal is then skimmed off the surface.

Moisture increases the weight of the coal, and consequently increases transportation and handling costs. In addition, moisture reduces the heating value. Drying of coal, after separation of impurities, usually is performed mechanically with hot air streams, using equipment such as centrifuges to remove the water added during wet cleaning. Thermal dewatering removes the final traces of moisture from the coal. All industrial dryers now in use are the continuous direct contact type, which employ convection for heat transfer. The six basic dryer designs are fluidized bed, suspension or flash, Multi-Louvre, vertical tray and cascade, continuous carrier, and drum.[16]

A number of alternatives to conventional beneficiation procedures have been devel-

oped within the past few years. Among these are oil-agglomeration, multistream coal cleaning, two-stage froth flotation, electrophoretic separation, and magnetic separation, all of which are physical processes, and hydrothermal processing, oxygen leaching, sulfur oxidation, and chemical comminution, which are chemical processes.[17] These processes range from the relatively simple improvements of conventional coal-cleaning techniques to processes that are very close to solvent-refined coal technology in sophistication and efficiency. DOE is conducting and supporting studies to improve desulfurization processes, and also is demonstrating an oil agglomeration process that separates fine rock from powdered coal. This latter process will be integrated with a wet high-gradient magnetic separation process to obtain a clean coal product low in moisture, ash, and pyrite.[12]

Transportation

Raw coal is transported to consumption points or processing facilities by rail, barge, truck, conveyor, or pipeline. Most coal in the United States is hauled by railroads. Table 4-6 shows coal shipments of bituminous coal by method of movement and consumer use. The numbers represent total coal traffic, including intermodal transfers (for example, between rail and water).

Unit trains, comprising coal cars that travel only between a particular mine and a particular plant, move about 50 percent of all coal transported by rail. These trains, which may be owned by utilities, coal companies, or railroads, may be 1.5 km long, and typically contain 100 hopper cars each with a capacity of 90 metric tons. Since these cars are used only for carrying coal and uncoupled only for maintenance, costly switching and other delays are avoided. These and other features, such as cars designed for automated loading and unloading, permit rapid service.

Coal is transported by barge on inland waterways primarily in the central eastern parts of the United States. Large quantities are moved on the Ohio and Mississippi Rivers and through the Great Lakes area. Most coal exported from the United States is shipped through the Hampton Roads, Virginia, area and through Baltimore, Maryland, where 4.5 million metric tons are handled annually. In addition, some of the coal transported on the Great Lakes is exported to Canada. Improved loading and unloading equipment, larger capacity barges, and the concept of unit barges (patterned after unit trains) all have been introduced by the barge industry to keep this form of coal transportation competitive with other modes.

Trucks are used primarily at surface mines to move coal from the mining pit to preparation facilities and to loading points or generating stations. Trucks are not cost-effective for moving large quantities of coal long distances. Conveyors also are used widely to transport coal in and near mines, and some conveyor systems have been built to transport coal over long distances. One system in Kentucky has a 16 km long conveyor belt designed to carry about 127,000 metric tons of coal per week from two mines to a dock on the Ohio River.[11]

Coal slurry pipelines are seriously considered by proponents who believe that railroad capacity would be insufficient to move the anticipated increases in western coal traffic.[18] In a slurry pipeline system, coal is pulverized, mixed with water, and pumped through an

Table 4-6. SHIPMENTS OF BITUMINOUS COAL TO ALL DESTINATIONS IN THE UNITED STATES, CANADA, AND MEXICO, BY METHOD OF MOVEMENT AND CONSUMER USE[a]
(Thousands of net tons)

Method of Movement and Use	1974	1975	1976
All rail	298,731	320,140	331,048
Electric utilities	205,601	235,576	246,032
Coke and gas plants	53,397	51,726	51,250
Retail dealers	3,876	2,837	2,183
All others	35,857	30,001	31,583
River and ex-river	102,517	107,023	107,503
Electric utilities	74,579	81,375	81,677
Coke and gas plants	22,825	21,436	22,712
Retail dealers	145	25	41
All others	4,968	4,186	3,073
Great Lakes	32,654	34,246	33,103
Electric utilities	16,490	17,340	16,833
Coke and gas plants	10,927	12,293	12,016
Retail dealers	595	467	502
All others	4,642	4,146	3,752
Tidewater	6,259	5,353	5,344
Electric utilities	2,465	1,693	1,243
Coke and gas plants	3,701	3,617	4,101
Retail dealers	–	–	–
All others	93	43	–
Truck	71,497	69,679	69,410
Electric utilities	50,859	51,056	52,671
Coke and gas plants	2,229	3,367	2,599
Retail dealers	2,176	1,714	1,411
All others	16,233	13,542	12,729
Tramways, conveyor, and private railroad	44,636	53,373	66,667
Electric utilities	42,557	51,515	64,602
Coke and gas plants	79	58	–
Retail dealers	–	–	–
All others	2,000	1,800	2,065
Total	556,294	589,816	613,075
Electric utilities	392,551	438,558	463,058
Coke and gas plants	93,158	92,497	92,678
Retail dealers	6,792	5,043	4,137
All others	63,793	53,718	53,202

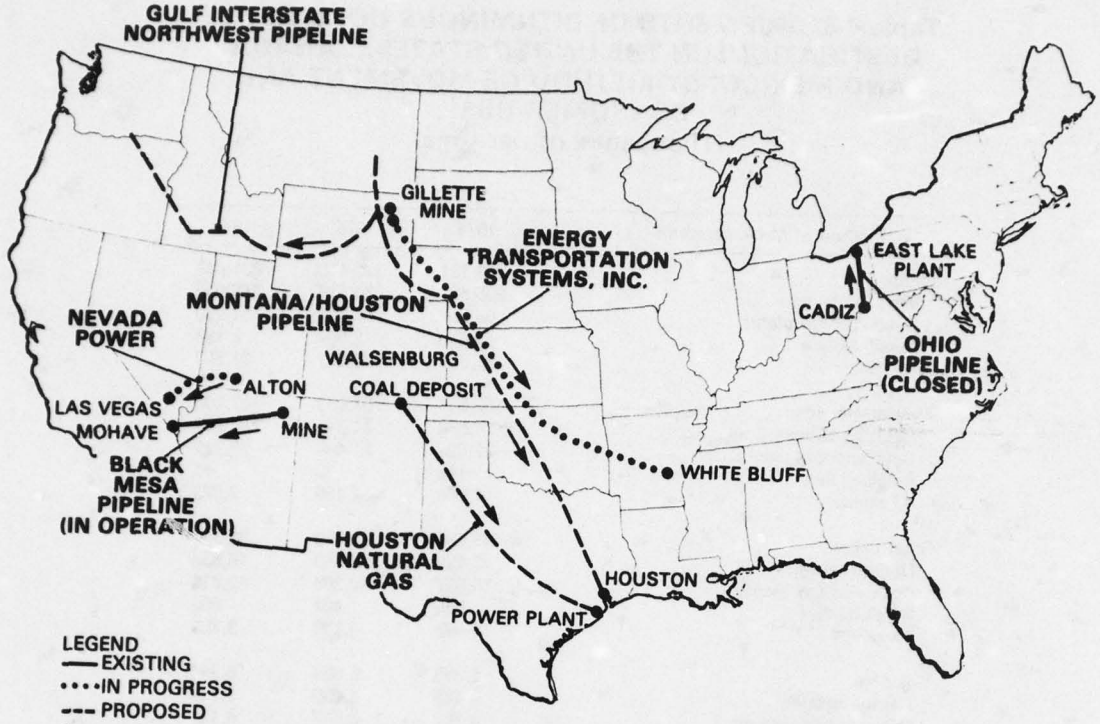
[a]Excludes Canadian Great Lakes commercial docks, U.S. Great Lakes and tidewater dock storage, coal used at mines and sales to employees, net change in inventory, and oversees exports.

Source: National Coal Association, *Coal Facts,* 1978-79.

underground pipeline. The coal is dewatered after transport. Figure 4-8 shows present and proposed coal slurry pipelines in the United States.

Storage

Storage of coal has become increasingly important due to the cost advantages associated both with the transport of large quantities of coal in unit trains, and large-volume



Source: U.S. Congress, Office of Technology Assessment, "A Technology Assessment of Coal Slurry Pipelines," March 1978.

Figure 4-8. COAL SLURRY PIPELINES

purchases. Coal must be stored properly, however, to avoid weathering, oxidation, and spontaneous combustion. When subjected to weathering and oxidation, coal's heating value can be reduced up to 5 percent during the first year.[16] During storage, coal also can lose its capability to form good-quality coke.

Coal can be stored in open or closed facilities. The method selected depends on the type of coal and the extent to which its properties are affected by weathering and oxidation. Three basic open storage stockpiling configurations are conical shaped (most common), wedge shaped (large capacity), and kidney shaped (large capacity, minimal area requirements, and simplified handling).

Closed storage facilities, while smaller in capacity than open storage, reduce weathering effects and combustion hazards and require less land area. A typical cylindrical steel storage bin, which may have a capacity of 900 metric tons, is designed to allow uniform movement of hopper cars through a loading station. Precast concrete silos are less expensive and can have greater capacity than the steel bins.

DIRECT COMBUSTION OF COAL

In 1977, about 75 percent of all coal consumed in the United States was burned in boilers to generate steam for electric power and other industries. Another 14 percent was converted to coke. The efficient combustion of coal for industrial purposes requires a system that differs with the rank or type of coal, the required firing rate (load capacity), and the time-profile and quality of the steam load.

The rank of the coal is an important determinant in the design of a combustion system, and different firing conditions are required because of differences in chemical composition. Other coal characteristics that contribute to the need for different firing techniques are amount and character of the ash (which determines the slagging temperature), sulfur content (which can require control methods such as coal preparation before combustion or flue gas scrubbing after combustion), and the coal's potential for generating fly ash (which can require stack gas treatment equipment, such as electrostatic precipitators).

Bituminous and subbituminous coals, lignites, and even small amounts of peat are used for steam production; very little anthracite now is mined. New surface mines in the central midwestern, gulf, and western states have expanded production of bituminous and subbituminous coals and lignite, both for transport to existing load centers (industrial and power generation) and for on-site power plants.

Conventional Coal-Fired Boilers

The three conventional methods for firing coal in a steam boiler are stoker, pulverized coal, and cyclone-firing. Stoker systems, developed in the late nineteenth century, were in widespread use until the 1920s. These systems are limited in size to boilers that can produce about 400,000 lb/hour of steam. For boilers with large capacities, other firing methods are more economical. The primary advantage of stoker systems is their versatility; they have a wide operating range and burn all types or ranks of coal.

Mechanical stoking provides continuous addition of fuel, permitting steady combustion. The air supply is adjusted so that complete combustion can be obtained with a minimum of excess air. Although the direction of the fuel movement and the propagation of the combustion zone depend upon the type of stoker, the underfire air generally passes upward through the fuel bed. A single-retort stoker will burn all coals from anthracite to lignite, but not necessarily with equal success. A coal's size, ash fusibility, and caking characteristics are important and influence the boiler's performance, which averages less than 30,000 lb/hour of steam. Multiple-retort stokers, which perform best with caking bituminous coals, can fire boilers with capacities of up to 500,000 lb/hour of steam. Spreader stokers will handle all ranks of coal except anthracite, and traveling stokers can handle all with the exception of strongly caking bituminous coals. A spreader stoker can fire boilers with a capacity of 75,000 to 400,000 lb/hour of steam, while the traveling stoker system has a maximum of 250,000 lb/hour.

Pulverized-coal firing was introduced in the 1920s and is still the most effective method of burning many coals, particularly those of higher grades and ranks. This system uses less

excess air than a stoker system and operates as a continuous process within specified design limitations. Pulverized-coal systems are generally found to be more economical than stokers with larger boilers, due to physical size and capacity considerations. In this type of system, which can fire a boiler to produce 100,000 to 4,000,000 lb/hour of steam, the coal is pulverized to about 200 mesh particle size (74 microns) and blown into the combustion chamber (Figure 4-9). Primary air (about 20 percent of the combustion air) is used to transport the coal to the burner. Secondary air (the rest of the air required for combustion) is introduced at the burner. Primary air is often derived from the drying air used in the coal pulverizer.

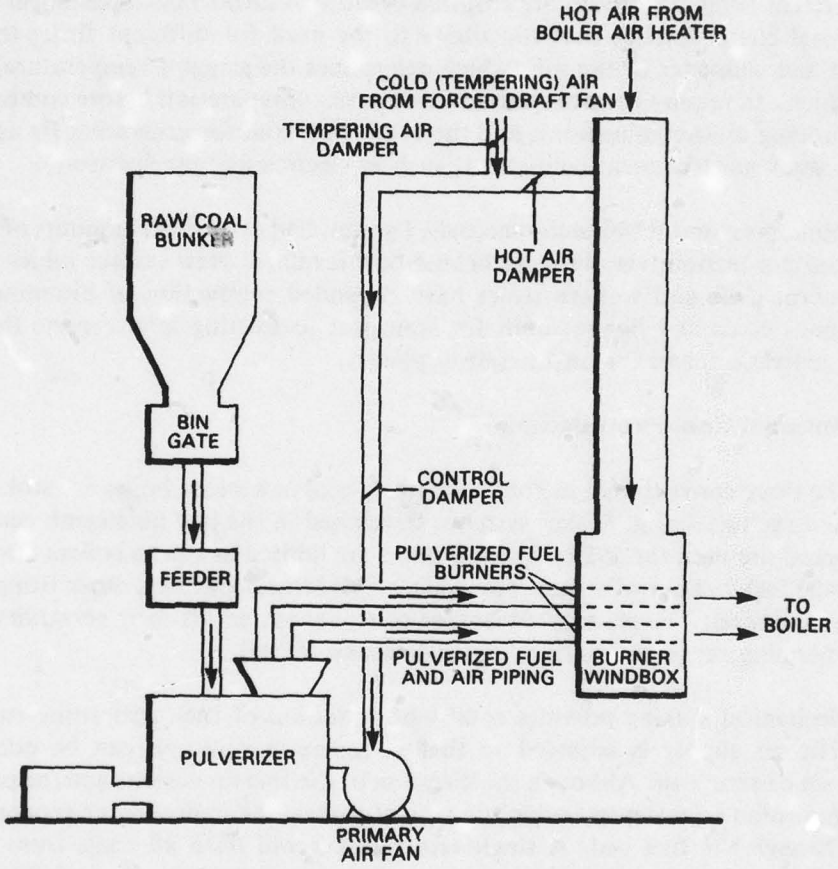


Figure 4-9. PULVERIZED-COAL FIRING SYSTEM

Problems associated with pulverized-coal firing systems involve controlling fly ash slagging and fly ash emissions. The combustion volume required for pulverized-coal firing must be larger than it is for other systems to prevent the buildup of low-temperature fusing ash particles on furnace walls and boiler tubes. The general range of heat release in pulverized-coal installations is 15,000 to 35,000 Btu/ft^3/hour, making such systems uneconomical for smaller sizes. Fly ash slagging can be controlled partially by adding air to cool the ash particles below the slagging temperature, but this lowers thermal efficiency. Fly ash emissions often are controlled by cyclones, impingement systems, settlement in the stack breedings, wet scrubbers, or electrostatic precipitators.

Cyclone-fired furnaces, developed since 1940, have several advantages over stoker and pulverized-coal firing systems: the fly ash content in the flue gas is reduced; the coal needs to be crushed only to about 4 mesh, reducing the cost of coal preparation; and the furnace size is smaller.[19] Furthermore, a cyclone furnace can be fired with lower ranks of coal (from low-volatile bituminous to lignites) and with coals of high ash content. The combustion process is more efficient because higher temperatures can be used than with stokers or pulverized-coal firing.

In the cyclone-fired system (Figure 4-10), crushed coal is introduced into the horizontal burner cylinder and the combustion air enters the burner tangentially along the cylinder periphery to produce a whirling pattern of coal particles. This combustion process is more rapid due to its higher turbulence.[19] Burners are targeted downward to direct slagging ash toward the bottom of the furnace. All cyclone furnaces are slag-top furnaces, meaning that the ash is accumulated in a "wet bottom" or molten slag condition. The molten slag may be either continually or intermittently withdrawn into a water tank where it is quenched and broken into finely divided slag droplets. In a dry bottom furnace, such as the pulverized-coal fired system, 70 to 90 percent of the ash is lost out the top of the furnace, with only 10 to 30 percent of the ash leaving through the ash hopper in the furnace bottom. A slag-top furnace may have 30 to 50 percent of the ash leaving through the ash hopper. A further cost benefit to this type of furnace is the normal absence of combustibles in the ash due to the molten ash phase of the process.

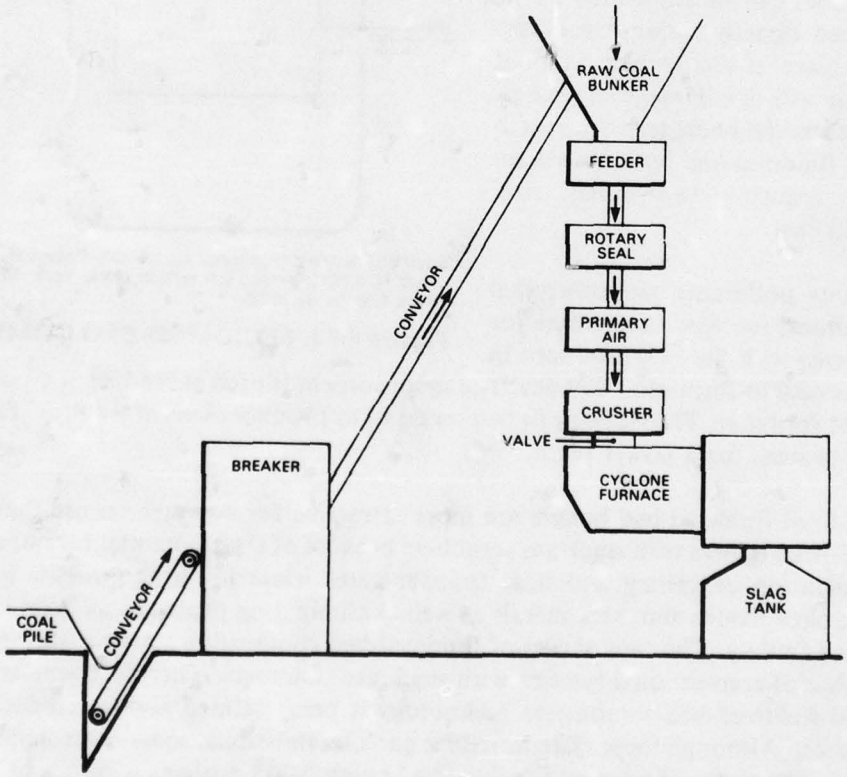
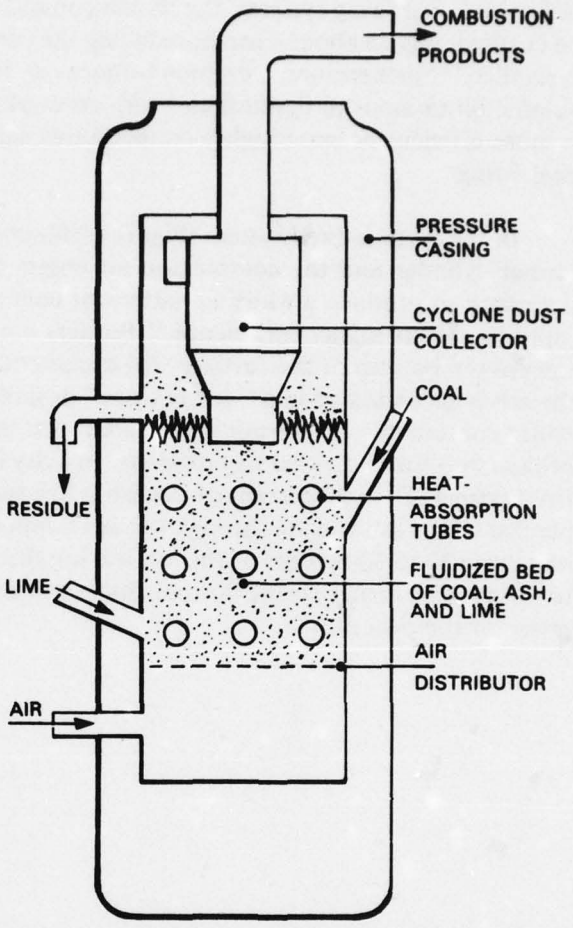


Figure 4-10. CYCLONE-FIRED SYSTEM

Fluidized-Bed Combustion

Development of atmospheric and pressurized fluidized-bed combustion systems offers the potential for efficiently utilizing the large U.S. reserves of high-sulfur coal in a manner that controls the emissions of gaseous pollutants, including sulfur dioxide (SO_2) and, to some extent nitrogen oxides. In a fluidized-bed boiler (see Figure 4-11), the combustion air passes upward through a grid or porous plate, which supports a thick (about 1 m) bed of granular, noncombustible material, such as coal ash and lime. The air fluidizes the material (expands the volume and turbulently mixes the material) and, with the relatively small amount of air used to inject the pulverized coal, supports the desired combustion. The heat transfer surfaces or boiler tubes can be embedded in the fluidized bed directly because combustion takes place at temperatures (about 870°C) that will not damage the tubes. The heat release and heat transfer coefficients of a fluidized-bed boiler are high, drastically reducing the boiler size, weight, and cost.



Source: *Chemical Engineers' Handbook,* Robert H. Perry and Cecil H. Chilton, eds., 5th edition (New York: McGraw-Hill Book Company, 1973).

Figure 4-11. FLUIDIZED-BED COMBUSTOR

Gaseous pollutants are controlled by the chemical reaction of the lime (or other sorbent) with the SO_2 produced in burning the coal to form solid sulfates. The spent sorbent is used as landfill or separated and regenerated for reuse. The sulfate can be processed to produce elemental sulfur. Figure 4-12 shows the process for a power plant.

Coal-fired fluidized-bed boilers are more attractive for commercial use than conventional coal-fired boilers with stack gas scrubbers because of their potential for improving net power generation efficiency and heat transfer rates while lowering emissions of sulfur oxides, nitrogen oxides and trace metals as well as eliminating problems associated with ash slagging and fouling. The capital cost of fluidized-bed combustion systems is expected to be less than that of conventional systems with stack gas scrubbers. Therefore atmospheric and pressurized fluidized-bed-combustion technology is being refined and developed for commercialization. Although these systems reduce gaseous emissions, some control measures are still needed. The status of selected fluidized-bed combustion projects is shown in Table 4-7.

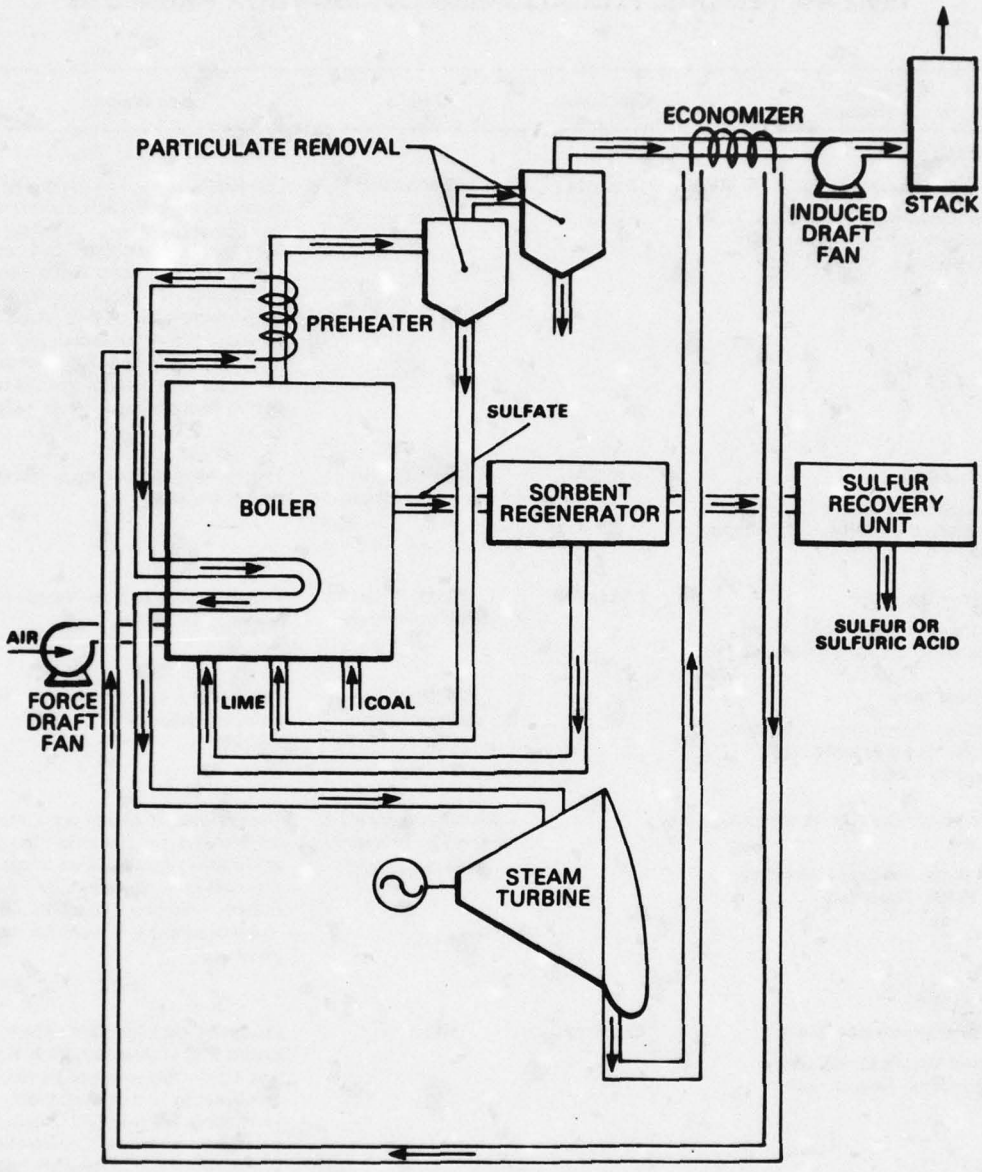


Figure 4-12. FLUIDIZED-BED COMBUSTION POWER PLANT

COAL LIQUEFACTION

Coal liquefaction is the conversion of coal to liquid fuel. This fuel, which is more versatile and easier to handle than a solid fuel, burns cleanly and has a low ash and sulfur content. Coal liquids were first produced about 50 years ago. Germany, because of a limited petroleum supply, began building synthetic fuel plants as an integral part of its rearmament program before World War II. Germany was producing about 25,000 bbl/day of liquid fuels from coal by 1939, and 100,000 bbl/day during World War II.[20-22] (Production of synthetic

Table 4-7. FEDERAL FLUIDIZED-BED COMBUSTION PROJECTS

Project[a] (Owner)	Coal Input	Output	Status
Atmospheric[b]			
Multicell fluidized-bed boiler, 30 MW (Pope, Evans and Robbins, Inc./ Monongahela Power Company, Rivesville, West Virginia)	15 ton/hr	300,000 lb/hr	This facility is the first major step toward commercial size central station power generation. Between April and August 1978, 1,054 hours of test operation were completed, including five periods of commercial power generation. A fire, which damaged the air preheater, induced draft fan, and associated duct work interrupted the testing, but the unit should be back in service in early 1979.
Industrial boiler (Fluidized Combustion Corporation/ Georgetown University, Washington, D.C.)	5 ton/hr	100,000 lb/hr saturated steam	This boiler is in the design and construction phase.
Industrial generator (Combustion Engineering/Great Lakes Naval Training Center, Illinois)	2.5 ton/hr	50,000 lb/hr superheated steam	This generator is in the design and construction phase.
Industrial boiler (Fluidized Combustion Corporation/ Battelle Memorial Institute, Columbus, Ohio)	1 ton/hr	25,000 lb/hr saturated steam	This boiler is in the design and construction phase.
Closed-cycle gas turbine technology test unit (Oak Ridge National Laboratory, Oak Ridge, Tennessee)		300-500 kW plus 2.5 million Btu/hr recoverable waste heat	The conceptual design completed for the test unit couples a coal-burning atmospheric fluidized-bed combustion system to an externally fired gas turbine. Ultimately, coupling will be to a closed-cycle, hot-air gas turbine generator.
Pressurized			
Combined-cycle pilot plant (Curtiss-Wright Corporation, Woodbridge, New Jersey)	5 ton/hr	13 MW	Design of the pilot plant, which includes a 12 ft diameter, 50 ft high pressurized fluidized-bed combustor and a waste heat boiler capable of generating 175 psig/377°F steam, is essentially complete. Construction is to begin in FY 1979, and shakedown testing is scheduled to begin in FY 1981.

[a]These projects are all supported under the DOE fossil fuel program.

[b]Atmospheric fluidized-bed combustion systems can be retrofitted to existing boilers, whereas pressurized fluidized-bed combustion systems cannot.

Source: U.S. Department of Energy, "Fossil Energy Research and Development Program of the U.S. Department of Energy, FY 1979," DOE/ET-0013(78), March 1978.

fuels dwindled after World War II.) South Africa began gasifying and liquefying coal in 1955 at its SASOL plant; a much larger plant, SASOL II is being built and should begin operating in the early 1980s. The combined output of the SASOL plants is expected to produce about 50 percent of the country's motor fuel needs (about 250,000 bbl/day).

Because coal liquefaction has not been economical when competing with low-priced natural crude oil, the United States currently is not operating or building commercial- or demonstration-scale coal liquefaction plants. However, DOE and industry are conducting research and development programs on liquefaction processes to improve conversion efficiency and make liquid fuels from coal more competitive. Furthermore, additional data are needed to allow reliable scale-up.[23-26] Table 4-8 describes some coal liquefaction processes being developed. The three most promising processes described are the H-Coal, Exxon Donor Solvent, and Solvent-Refined Coal (SRC) processes. The H-Coal (Figure 4-13) and Exxon (Figure 4-14) processes are being scaled up. Two versions of the SRC process are being tested: SRC-I (Figure 4-15), which produces solid fuel, and SRC-II, which produces liquid (Figure 4-16). The most suitable of the processes will be demonstrated on a larger scale.[27]

To form liquid hydrocarbons from coal, its hydrogen-to-carbon ratio (which is about 0.9:1) must be increased by at least a factor of two (crude oil has a hydrogen-to-carbon ratio of about 2:1). There are basically three ways to accomplish this: by adding hydrogen, by removing carbon, or by breaking the coal down into individual carbon atoms, and then rebuilding. Since there are two methods for adding hydrogen to coal, coal liquefaction processes can be divided into four broad categories: direct hydrogenation, solvent extraction, pyrolysis, and indirect liquefaction.

Direct Hydrogenation

In coal hydrogenation, hydrogen is added directly. Pulverized feed coal is slurried in a recycled coal-derived solvent mixed with a hydrogen-containing gas, and reacted at high temperatures and pressures. The reaction may be noncatalytic, pseudocatalytic, or catalytic. In noncatalytic reactions, certain coals react more readily with hydrogen than others, probably because of the catalytic effect of specific coal ash constituents. In pseudocatalytic reactions, a portion of the reaction product is recycled to the feed slurry to increase ash content (and, thus, catalytic activity) in the reactor. Catalytic reactions, which use a catalyst to speed the reaction, include the Synthoil process and the H-Coal process, which is DOE's only active direct hydrogenation project.[12,30]

The products of direct hydrogenation may be solid or liquid at room temperature, depending on reaction conditions. Generally, reaction products are separated by flashing at low pressure and removing unconverted coal by filtration or fractionation.

Solvent Extraction

Solvent extraction is a liquefaction process involving the addition of hydrogen indirectly from recycled, hydrogen-rich liquid (donor solvent) derived from coal. The primary difference between extraction and hydrogenation is that a portion of the liquids produced in the extraction process is catalytically hydrotreated at elevated temperature and pressure to produce the donor solvent for recycle. The Exxon Donor Solvent process and the SRC processes, important techniques for liquefying coal by extraction, are major DOE projects in the advanced development stage.[12]

Table 4-8. COAL LIQUEFACTION PROCESSES

Process (Owner)	Process Type	Temperature and Pressure	Products	History and Status
Catalytic coal liquefaction (Gulf Research and (Development Company)	Hydrogenation, catalytic, fixed catalyst bed	900°F 2,000-4,000 psig	Synthetic crude oil, gas	After several years of bench-scale research, Gulf, in January 1975, began operating a 1 ton/day pilot plant, designed to yield 2 bbl of oil/ton of dry ash-free coal. Research is concentrating on improving the catalyst.
Clean coke process (USS Engineers and Consultants)	Dual process: 1. Hydrogenation, non-catalytic 2. Pyrolysis, indirect, fluidized bed	825-925°F 3,000-4,000 psia 1,200°-1,400°F 90-100 psia	Fuel gas, light oil (aromatics), heavy liquids (tar and tar acids) char pelletized to form metallurgical coke (very low in sulfur)	The Office of Coal Research awarded a contract in 1972 to construct and operate a 500 lb/day process development unit consisting of five separate units. During 1976 and 1977, development studies and process development work were completed on the carbonization (pyrolysis) unit; process development work on the four other units was completed in 1978 to demonstrate process applicability to a wide range of coal types.
COALCON (Union Carbide)	Indirect pyrolysis or hydrocarbonization	1,040°F 555 psig	Fuel gas, liquefied petroleum gas, light oil, fuel oil	Union Carbide began work on this process in 1936. The 500 ton/day semi-works plant and 20 ton/day process development unit were operated until the mid-1960s. In the early 1970s, the process was reactivated. In 1975, Union Carbide received a contract from the Office of Coal Research to design, build, and operate a 2,600 ton/day demonstration plant. Despite problems in 1976 with handling agglomerating eastern coals, scaling up to demonstration plant size, as well as termination of government financial support, Union Carbide is continuing its research.

Table 4-8. COAL LIQUEFACTION PROCESSES (CONT'D)

Process (Owner)	Process Type	Temperature and Pressure	Products	History and Status
COGAS (COGAS Development Company and FMC Corporation (COED))	COED, direct pyrolysis, four-stage fluidized bed	Stage 1: 600°F Stage 2: 850°F Stage 3: 1,000°F Stage 4: 1,500°F All stages: 6–10 psig	Fuel gas, synthetic crude oil, char	Development of the process started in 1962 under sponsorship of the Office of Coal Research. The 36 ton/day COED pilot plant began operating in 1970, and COED syncrude was tested successfully in a Navy destroyer in 1974. In 1972 the COGAS Development Company was formed to develop a system for gasification of the char formed in the COED process. Pilot plants in England and New Jersey have demonstrated most of the key features of the COGAS process.
Consolidated Synfuel (Consolidated Coal Company and Fluor Engineers and Constructors, Inc.)	Extraction, donor solvent produced by process	800°F 3,000 psig	Fuel gas, liquid synthetic fuels (liquefied petroleum gas, gasoline)	Development began in 1963 under contract with the Office of Coal Research. (It was originally called "Project Gasoline.") A 20 ton/day pilot plant was completed in 1967 and operated until 1970. DOE is continuing work at this location, primarily to develop information on process module performance.
CS/R Flash Hydropyrolysis (Cities Services Research and Development)	Indirect pyrolysis: hydrogasification Stage 1: rapid devolatilization (pyrolysis) Stage 2: hydrogenation of the coal/char	1,470–1,800°F 300–2,500 psig Vapor residence time: 350–3,500 msec	Methane, ethane, benzene, light oils, char (used to produce hydrogen)	Process development began in 1974 with a bench-scale reactor system processing 2 to 4 lb/hr of coal. Over 50 runs were made using Montana Rosebud subbituminous coal. Construction of a 250 ton/day pilot plant in Cranbury, New Jersey, is being considered.

Table 4-8. COAL LIQUEFACTION PROCESSES (CONT'D)

Process (Owner)	Process Type	Temperature and Pressure	Products	History and Status
Exxon Donor Solvent (Exxon Research and Engineering Company)	Extraction, recycle donor solvent	800°F 1,500-2,500 psig	Fuel gas, naphtha, middle distillate, heavy distillate	From 1966 to 1973, Exxon identified the basic process flow plan using a 0.5 ton/day integrated pilot plant. In 1976, a 1 ton/day process development unit began operation in Baytown, Texas, processing bituminous and subbituminous coals. ERDA began supporting the development of this process in 1976, and in 1977 EPRI and Phillips Petroleum joined the venture. Construction of a 250 ton/day coal liquefaction plant in Baytown, Texas, began in 1978, and is scheduled for completion in 1980.
Fischer-Tropsch (M. W. Kellogg/Lurgi)	Indirect liquefaction, liquefaction of synthesis gas in a fixed-bed catalytic converter	625°F 320 psig	Synthetic natural gas, liquefied petroleum gas, naphtha, diesel fuel, premium fuel oil, alcohols	In 1932, a 20 bbl/day plant was operating in Germany; by 1939, nine plants were producing 16,000 bbl/day of gasoline, all operating at 0 to 300 psig using a cobalt catalyst. The Bureau of Mines constructed an 80 bbl/day demonstration plant at Louisiana, Missouri, which operated from 1949 to 1953. In the Republic of South Africa, the SASOL plant, completed in 1955, produces about 6,500 bbl/day of liquid hydrocarbons. A new plant, SASOL II to be completed in 1980, will have about 10 times the capacity of the existing plant.
H-Coal (Hydrocarbon Research, Inc.)	Catalytic hydrogenation, ebullated catalyst bed	805°F 2,250-2,700 psig	Low-sulfur fuel gas, naphtha, light fuel oil, heavy distillate, residual fuel oil	Development began in 1964, based on experience with the H-Oil process. A 2.5 ton/day process development unit for synthetic crude oil and boiler fuel production was operated successfully and a 600 ton/day pilot plant is being constructed. The pilot plant is being funded by industry (20 percent) and DOE (80 percent), and is expected to cost $93 million.

Table 4-8. COAL LIQUEFACTION PROCESSES (CONT'D)

Process (Owner)	Process Type	Temperature and Pressure	Products	History and Status
Methanol-to-Gasoline (Mobil Research and Development Corporation)	Indirect liquefaction, entrained-bed, synthetic zeolite catalyst	600-650°F 280-300 psig	High-octane gasoline	For 25 years Mobil has been studying the use of synthetic zeolite catalysts for catalytic cracking; one of these was found to convert methanol to high-octane gasoline. Under a DOE contract, a 4 bbl/day fluid bed pilot plant was designed, built, and put onstream in September 1977. The product, 96-octane gasoline, can be used directly in an automobile engine. A 100 bbl/day unit using an entrained bed is planned.
Occidental Coal Pyrolysis (Occidental Research Corporation)	Direct "flash" pyrolysis, entrained bed	1,100°F <50 psig	Fuel gas, synthetic crude (or clean fuel oil), char	Development began in 1969 to convert high-sulfur coals to low-sulfur fuels. A 3 ton/day process development unit for the pyrolysis of solid waste was constructed with EPA support. In 1975, this unit began operating on coal.
Rocketdyne Flash Liquefaction (Rocketdyne Division, Rockwell International)	Indirect pyrolysis, coal and hydrogen mixed and conditioned almost instantaneously	1,800°F 1,000 psig	Fuel gas, light oil, heavy oil, char	Development started in 1975, and experimental work on a 6 ton/day unit was completed by the end of 1976. Testing on a 24 ton/day unit began in 1977 to further develop the process. In January 1979, DOE awarded Rockwell an $18 million contract to design and construct a 100 ton/day pilot plant that could lead to a 5,000 ton/day commercial plant.
Solvent Refined Coal (Pittsburg and Midway Coal Mining Company)	SRC-I: Solvent extraction, coal dissolved in recycle solvent, noncatalytic hydrogenation	800°F 1,000 psia	Solid fuel (melting point—350-400°F)	Development began in 1962 with bench-scale evaluation of the Pott-Broche process. The process was successfully demonstrated in 1965 in a 50 lb/hr con-

Table 4-8. COAL LIQUEFACTION PROCESSES (CONT'D)

Process (Owner)	Process Type	Temperature and Pressure	Products	History and Status
Solvent Refined Coal (continued)	SRC-II: Solvent extraction, coal dissolved in solvent, slurry recycled, pseudo-catalytic hydrogenation	800-875°F 1,500-2,500 psig	Liquid distillate and some solid as above	tinuous flow unit. In October 1974, full operation began of a 50 ton/day pilot plant at Fort Lewis, Washington. This plant operated in both the SRC-I and SRC-II modes. A 6 ton/day plant has also been built in Alabama. This unit operates in the SRC-I mode.
Synthoil (Pittsburgh Energy Technology Center and Foster Wheeler Corporation)	Catalytic hydroliquefaction, fixed catalyst bed	840°F 2,000-4,000 psig	Low-sulfur, low-ash synthetic fuel oil (17,400 Btu/lb)	Based on some early work at the Bureau of Mines in 1936, work on this process began in 1969 with a 5 lb/hr unit. Extended operations on a 0.5 ton/day process development unit, completed in 1973, demonstrated the broad applicability of the process to a wide variety of coals. Construction of a 10 ton/day process development unit was started in 1975 by Foster Wheeler, with completion set for 1979. Because the Synthoil process failed to perform adequately in bench-scale tests, the unit was placed in standby condition for possible use in developing advanced processes.
TOSCOAL (The Oil Shale Corporation (TOSCO), Rocky Flats Research Center)	Direct pyrolysis, indirect heating via hot ceramic balls	800-1,000°F Atmospheric pressure	Naphtha, gas oil, residual oil, char	The Toscoal process is the application to coal of the TOSCO II oil shale process. The 25 ton/day pilot plant (operational since 1969) produced a solid char containing 80 percent of the heating value of the coal in 50 percent of its weight. An economic analysis of a 7,000 ton/day plant has been carried out, but no plans for its construction have been made.

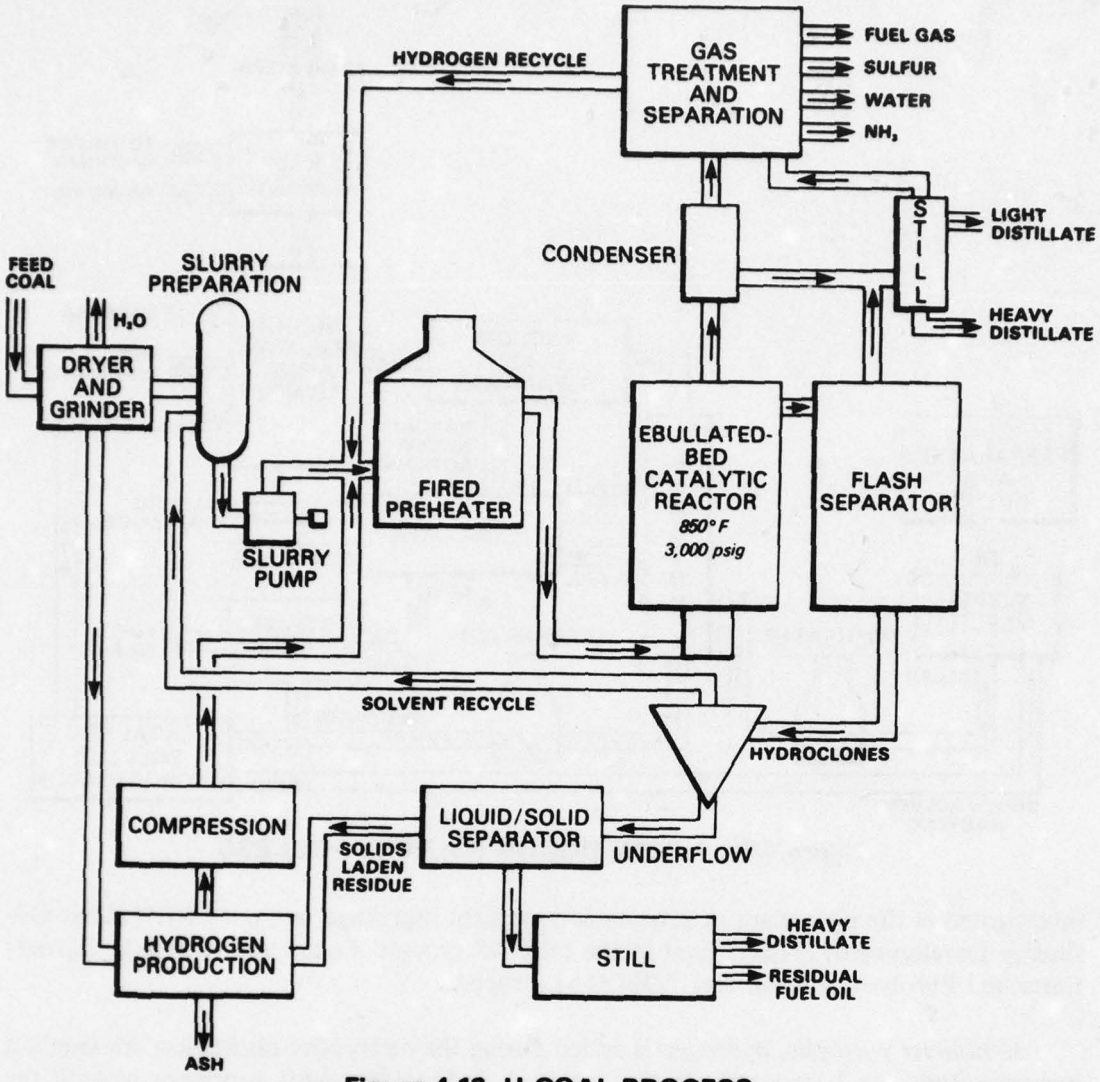


Figure 4-13. H-COAL PROCESS

Pyrolysis

In pyrolysis (the removal of carbon), or destructive distillation, feed coal is heated to an elevated temperature in such a way that its molecular structure is broken down and volatile components are driven off, some of which can be condensed as a liquid. The result is a hydrogen-rich product in the distillate and a carbon-rich residue or char. The products are gas, tar (which can be hydrotreated to produce low sulfur liquids), and char (which can be gasified using steam and oxygen or air to produce a synthesis gas consisting primarily of hydrogen and carbon monoxide).

Pyrolysis can be direct or indirect. In direct pyrolysis, the coal is pyrolyzed directly without the addition of hydrogen. Examples of direct pyrolysis processes, which have been

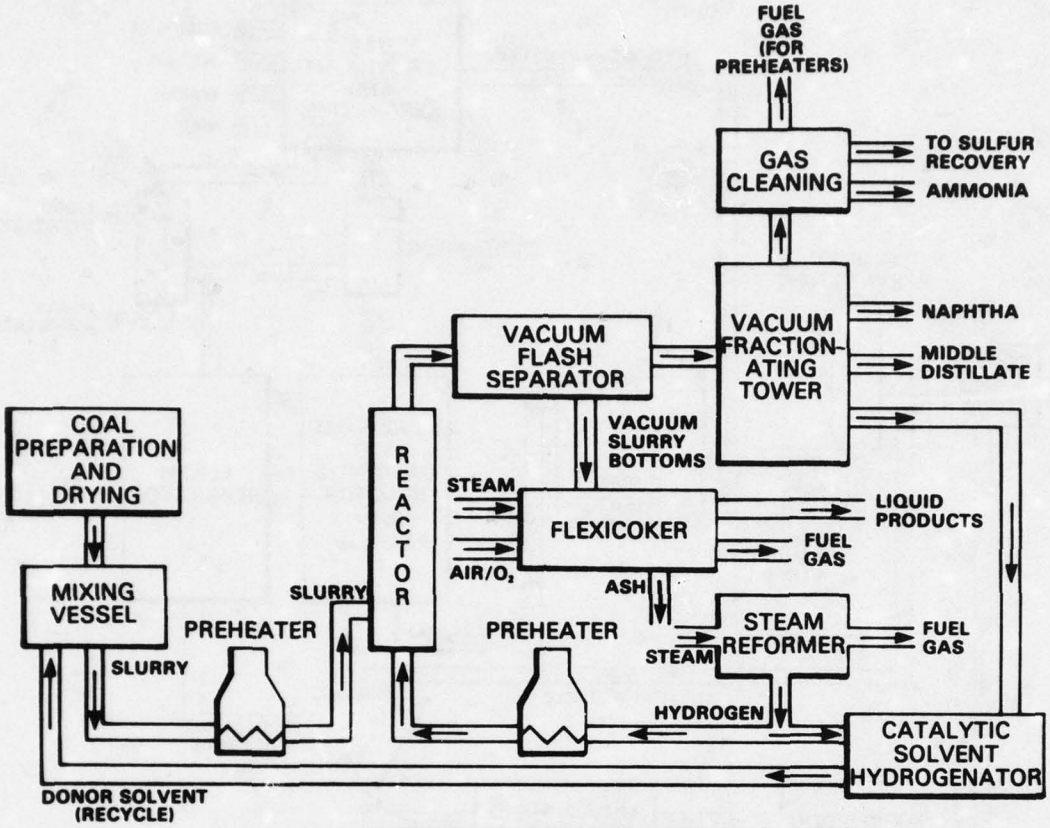


Figure 4-14. EXXON DONOR SOLVENT PROCESS

investigated at the pilot plant or process development unit stage, are the COED (Char-Oil-Energy Development) process used in the COGAS process, Occidental (formerly Garrett) Entrained Pyrolysis process, and TOSCOAL process.

In indirect pyrolysis, hydrogen is added during the destructive distillation, making it a hydropyrolysis, or hydrocarbonization process. Indirect pyrolysis processes include the Coalcon Hydrocarbonization process, Clean Coke process (part of feed coal), Rocketdyne Flash Liquefaction process, and Cities Service Flash Hydropyrolysis process.

Indirect Liquefaction

The key steps in indirect liquefaction processes are the gasification of feed coal to produce a synthesis gas followed by purification of the synthesis gas and conversion to liquids in a catalytic converter using Fischer-Tropsch technology. The liquid products are separated by fractionation, and a significant amount of intermediate- or high-Btu gas can be produced. The major thrust of developmental work in this country is focused on the production of methanol from the synthesis gas followed by the conversion of methanol to gasoline. In the United States, none of these processes has been developed beyond the laboratory and research stage.[21,23,25,26]

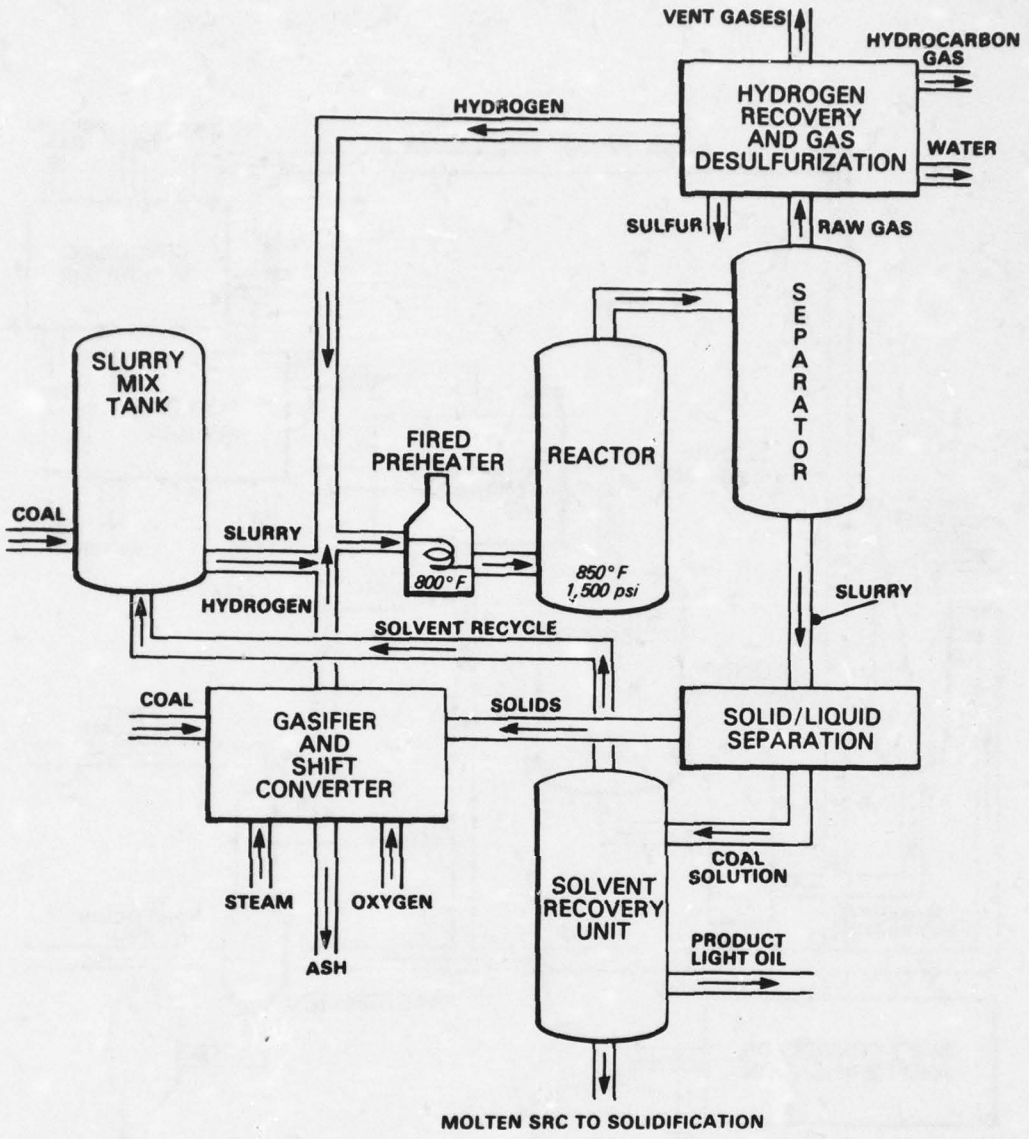


Figure 4-15. SRC-I PROCESS

COAL GASIFICATION

Gas was first manufactured from coal in the eighteenth century by heating coal in the absence of air. The first coal-gas company, which distributed its product for lighting, was chartered in London in 1812; the first U.S. company was chartered in 1816. City gas, a mixture of carbureted water gas (made by spraying water or steam on red-hot coal or coke) and coal or coke-oven gas (made by heating coal in the absence of air), had a heating value of about 500 Btu/scf. City gas was the common source of fuel for cooking, domestic hot water, and street lighting for 150 years. A lower quality gas—producer gas, with a heating value of

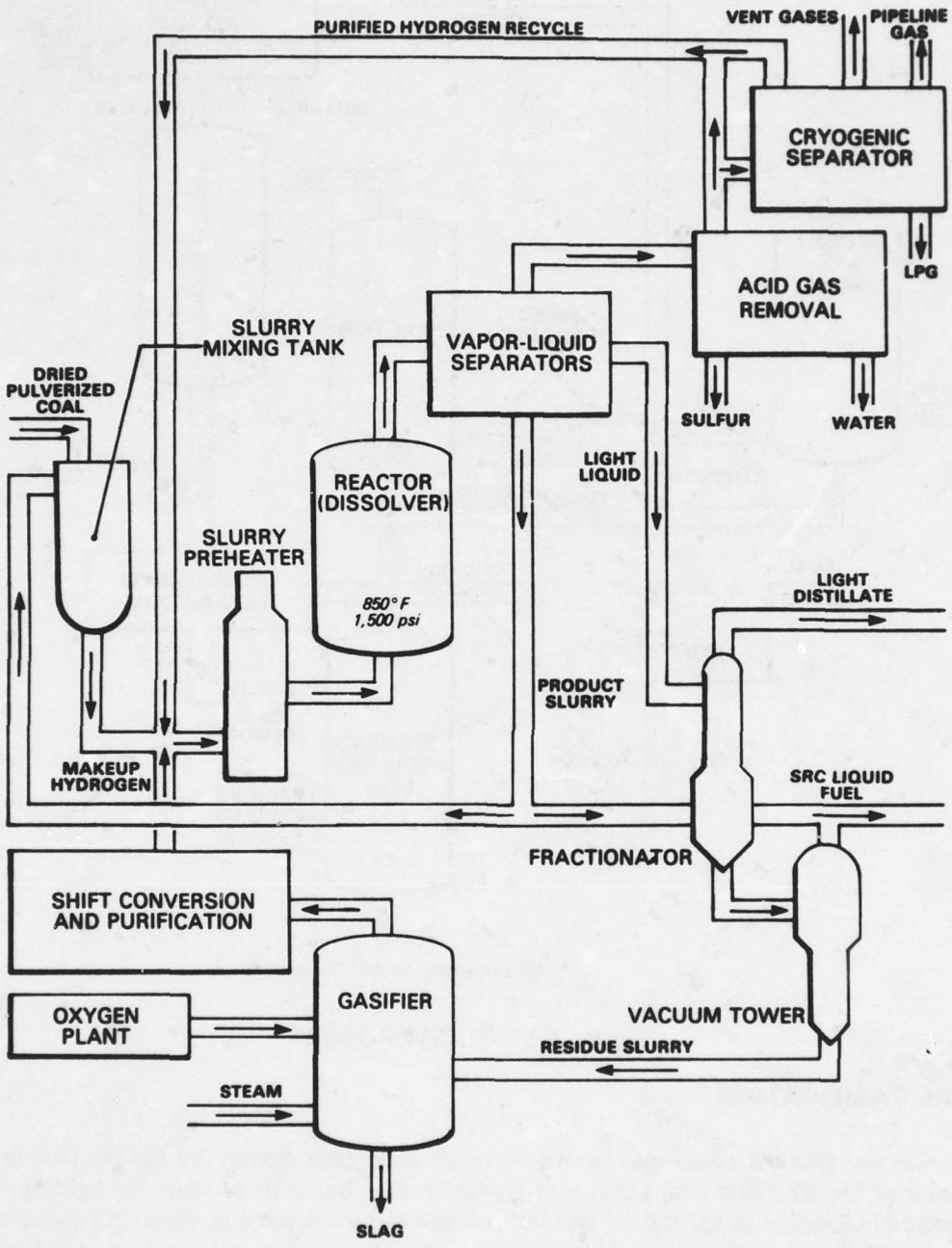


Figure 4-16. SRC-II PROCESS

110 to 160 Btu/scf—was used widely as an industrial fuel. Producer gas was made by passing a mixture of air and steam over hot coal to produce carbon monoxide.

Although coal conversion technology has developed considerably since 1850, the discovery of plentiful supplies of natural gas made city gas no longer economical. (Natural gas, with a heating value of about 1,000 Btu/scf, is more economical to transmit through city pipelines.) As a result of recently projected shortages of natural gas, however, the United States has renewed its interest in developing technology for producing gas from coal. To replace natural gas, synthetic natural gas (SNG)—gas with heating value equal to that of natural gas—is needed. There are several commercially proved coal gasification processes. The two most important are the Lurgi pressurized process (based on 40 years of continuous development) with 14 commercial plants comprising 65 gasifiers around the world, and the Koppers-Totzek process with 16 plants in Europe (the first in Finland in 1952) and Asia, comprising 48 gasifiers in operation or under construction; however, none of these plants is operating in the United States. Accordingly, DOE is sponsoring the development of gasification processes to produce high-Btu gas (SNG with a heating value of 1,000 Btu/scf), medium-Btu gas (300 to 650 Btu/scf), and low-Btu gas (100 to 250 Btu/scf). Table 4-9 describes some coal gasification processes being developed. Medium- or low-Btu gas often is called "industrial fuel gas" because it can be used economically only near the point of production; the low heating value precludes transmission by pipeline. Medium-Btu gas can usually be converted to SNG by methanation, whereas low-Btu gas contains too much nitrogen to allow for this.

Converting coal to gas requires a chemical and physical transformation. Because the types and ranks of coal differ, different processes are required to effect this transformation. All coal gasification processes require at least three steps: preparation, gasification, and gas purification. In addition, some processes require pretreatment (if the fuel is a caking coal). If the final product is to be SNG, two additional steps are required: shift conversion to adjust the ratio of hydrogen to carbon monoxide to 3:1, and methanation to convert the carbon monoxide to methane. (No known coal conversion process can produce high-Btu gas without a methanation step.) A generalized flow-sheet depicting the various steps is shown in Figure 4-17.

Preparation

Two basic coal preparation methods are used: one for processes using fixed-bed reactors (such as Lurgi) and another for processes using fluidized-bed reactors. Fixed-bed reactors require a sized coal no larger than 5 cm and no smaller than 0.3 cm. This range is controlled strictly to achieve maximum gasifier output with minimum process difficulties from carry-over of fine coal particles into the gas stream. Fluidized-bed reactors require fine coal (less than 0.3 cm).

While standard coal preparation equipment is available commercially, crushing and screening techniques are being tested on the particular coal to be used for the gasification processes being developed. The test results will be used to improve engineering design and equipment selection.

Table 4-9. COAL GASIFICATION PROCESSES

Process (Owner)	Process Type	Temperature and Pressure	History and Status
HIGH-BTU			
BI-GAS (Bituminous Coal Research, Inc.)	Entrained bed, oxygen blown, two-stage	Stage 1: 2,200°F 1,500 psig Stage 2: 2,700-3,000°F 1,500 psig	Process development began in December 1963. A 120 ton/day pilot plant was completed in 1976, and operations began to obtain design data for a larger plant. In 1979, the plant is to be deactivated.
CO_2 Acceptor (Consolidation Coal Company)	Fluidized bed, regenerator for acceptor (limestone or dolomite)	Gasifier: 1,480-1,550°F 150 psig Regenerator: 1,850°F 150 psig	Research began in 1948, then was discontinued until 1962. In 1964 OCR began supporting the process. A 40 ton/day pilot plant began operating in 1971 to identify and resolve process and equipment problems relevant to commercialization. Process efficiency of 77 percent has been demonstrated. The pilot plant was operated on an integrated basis with a liquid-phase methanation process. The project has been suspended for lack of funds.
COGAS			See Table 4-8.
Conoco Slagging Lurgi (Conoco Coal Development Company)	Fixed bed	1,500-2,000°F 300 psig	The Lurgi gasification process has been operated commercially since the 1930s; research demonstrated the advantages and feasibility of the slagging operation. DOE awarded a contract for the design of a 60 million scf/day high-Btu gas plant in Noble County, Ohio, using four slagging Lurgi gasifiers, which will be fed 3,800 tons/day of high-sulfur coal. This is the first phase of a $370 million, three-phase project that includes construction and operation of the plant. Conoco has demonstrated that the reactor could work with highly caking, high-sulfur coal. In June 1978, a 48-hour test run was successfully completed during which 970 tons of raw untreated Pittsburgh No. 8 highly caking, high-sulfur coal produced 23 million scf of natural gas.
Exxon Catalytic Coal Gasification (Exxon Research and Engineering Company)	Fluidized bed, alkali metal catalyst (K_2CO_3), no pretreatment required for caking coals	1,200-1,400°F 500 psig	In 1967, Exxon began work on coal gasification, and in 1971 began work with alkali metal catalysts. In 1975, an existing 0.5 ton/day process development unit was reworked to operate as a catalytic gasifier; tests were run until 1977. Exxon is building a 1 ton/day process development unit with its own funds near Baytown, Texas; DOE is providing funds for operating the unit to mid-1980. During FY 1978, the feasibility of converting an existing pilot plant to the Exxon process was studied; the synthane plant appears most suitable. Basic and detailed design are expected in FY 1979.

Table 4-9. COAL GASIFICATION PROCESSES (CONT'D)

Process (Owner)	Process Type	Temperature and Pressure	History and Status
Hydrane, now being developed as hydrogasification (Pittsburgh Energy Technology Center)	Entrained bed two-zone reactor, produces gas containing over 70 percent methane	1,700-1,800°F 1,000 psig	The Hydrane process was developed by BOM to produce methane by the hydrogasification of coal. During 1978, it was concluded that the two-zone entrained-bed reactor was too complex for commercial application. A 10 ton/day "second generation" single-stage, short residence time hydrogasifier based on rocket principles is now under development.
	Free-fall reactor or flash hydrogasifier	1,950°F 1,500 psig 750 msec residence time	Tests are under way at two levels of operation: 2 to 4 lb/hr and 500 lb/hr. The best results for bituminous coal were 50 percent carbon conversion. Plans call for a hydrogasification feasibility study; advanced development and preliminary design in FY 1978-81; and design, construction, and operation of a very large pilot or demonstration plant in FY 1980-85.
HYGAS (Institute of Gas Technology)	Fluidized bed, pretreatment at 750°F for caking coals	Stage 1: 1,200°F 1,000-1,500 psig Stage 2: 1,700-1,800°F 1,000-1,500 psig	The HYGAS process has been under investigation since 1946. Process development unit studies were performed from 1964 to 1967. An 80 ton/day pilot plant was operated with hydrogen from reforming natural gas from 1971 to 1974. During 1974, a steam-oxygen gasification unit was designed, constructed, and integrated into the bottom of the HYGAS reactor. Integrated operation of the pilot plant with the steam-oxygen system was achieved in mid-1974, and technical feasibility of the methanator step was demonstrated during 1974-76 on several coals. Depending on the status of the overall project, the HYGAS pilot plant will be operated for a certain period in FY 1979 for backup in the detailed design of a demonstration plant. The conceptual design for a commercial-scale plant to convert coal to pipeline-quality synthetic gas utilizing the HYGAS process was completed in 1978. (HYGAS was not one chosen by DOE for full design of demonstration plants.)
Self-agglomerating ash burner (Battelle Memorial Institute, Columbus Laboratories)	Fluidized bed	Gasifier: 1,800°F 100 psig	A 25 ton/day pilot plant was completed in 1976 to develop the two-stage process begun in 1972. Numerous attempts at integrated operation of the combustor and gasifier were unsuccessful, and the plant was mothballed in June 1978.

Table 4-9. COAL GASIFICATION PROCESSES (CONT'D)

Process (Owner)	Process Type	Temperature and Pressure	History and Status
Synthane (U.S. Bureau of Mines, Pittsburgh Energy Technology Center—plant being operated by Lummus Company)	Fluidized bed, steam and oxygen blown, pretreater used for caking coals	1,800°F up to 1,000 psig Pilot plant: 1,800°F 600 psig	The process has been under development since the early 1960s. A 75-ton/day pilot plant was completed in 1976 and operated successfully on Rosebud subbituminous coal during 1976-77. In late 1977, tests with agglomerating coals were begun. Mechanical reliability tests were planned for FY 1979, but in December 1978, the Bruceton plant was shut down because of insufficient funds.
LOW-BTU			
Entrained bed gasification, atmospheric pressure (Combustion Engineering, Inc.)	Two-stage entrained bed	Stage 1: 1,600°F Stage 2: 3,200°F atmospheric pressure	Operation of a 5 ton/hour pilot plant in Windsor, Connecticut, began in October 1977 and will run through FY 1979 to determine the effect of operating parameters such as air-coal ratio, coal-steam ratio, and reaction temperature on the gas composition and heating value. Cost and performance for a commercial-size plant will be estimated.
Fast Fluid-Bed (Hydrocarbon Research, Inc.)	Fluidized bed	2,000-2,400°F 10 atm	Cold-flow model tests were completed in FY 1977 to determine the solid flow dynamics for design conditions. A 7 ton/day process development unit is being built.
Fluidized-bed *two-stage* Pressurized (Westinghouse)	Fluidized bed, desulfurization with dolomite	Stage 1, devolatilizer: 1,600°F 175 psig Stage 2, gasifier: 2,000°F 175 psig	A process development unit with a coal feed design capacity of 1,200 lb/hr was completed in 1975, and a test program initiated to establish the operating characteristics of the gasification system and provide data for developing scale-up factors for a pilot plant. During 1976, the devolatilizer subsystem was tested with a variety of feed coals and conditions, ending with a 7-day continuous run on two highly caking Pittsburgh seam coals. These tests demonstrated that the unit can devolatilize caking coals without pretreatment. Tests during 1977 demonstrated that the gasifier-combustor can gasify various feedstocks and generate a gas satisfactory for operation of the first stage of the process, i.e., the devolatilizer. Integrated operation will be used to obtain data on performance and process economics to scale up the process. DOE plans to terminate the project in February 1980.

Table 4-9. COAL GASIFICATION PROCESSES (CONT'D)

Process (Owner)	Process Type	Temperature and Pressure	History and Status
Fluidized-bed gasification Three-stage (Tri-Gas), pressurized (Bituminous Coal Research, Inc.)	Three fluidized beds, no pretreatment needed for caking coals	Stage 1, pretreater: 1,200°F Stage 2, gasifier: 2,000 °F Stage 3, char combustor: 2,100°F	Successful laboratory studies led to the construction of a 100 lb/hr process development unit in December 1975. Operation of the unit started in 1975 using western noncaking coals. In mid-1976, tests at low temperature (between 800 and 900°F) demonstrated the ability to produce a noncaking product char in stage 1 from Illinois caking coal. A major problem is the large heat loss in stage 3.
GEGAS-D (General Electric Research and Development Center)	Fixed bed	1,000°F 340 psig	General Electric is developing this process to provide design basis for an integrated coal-fired gas turbine combined-cycle system. Tests on a 50 lb/hr atmospheric gasifier provided much of the design for the 24 ton/day, 340 psi gasifier, which has operated at rated conditions on eastern caking coals.
Kilngas (Allis-Chalmers and 11 companies)	Refractory lined rotary kiln, handles caking coals and fines	Proprietary process	Development work is over 60 percent complete with a 40 ton/day pilot plant in operation. A 500-600 ton/day pilot plant to produce gas for generating about 50 MW of electricity is expected to be operational in 1982.
Molten Salt (Rockwell International Corporation)	Molten sodium carbonate retains the sulfur and ash in the melt, handles both caking and noncaking coals	1,600-1,800°F 300-450 psig	Before December 1974, extensive experimental work was done to develop the molten salt gasification process. Following bench-scale tests, Rockwell International concluded that the molten salt process was sound, and that a pilot plant should be built to demonstrate the potential for commercialization. During 1976, further tests were carried out on a 120 lb/hr 3-ft inside diameter test reactor, and a 120 ton/day process development unit was engineered. The project was terminated in March 1976 as the cost was considerably higher than anticipated. A new project began in April 1976, to design, construct, and operate a 1 ton/hour process development unit located at Santa Susana, California, which will be designed for operation at 1,800°F and pressures up to 300 psig. Detailed design was completed in June 1977. The project is scheduled to be completed in FY 1980.

Table 4-9. COAL GASIFICATION PROCESSES (CONT'D)

Process (Owner)	Process Type	Temperature and Pressure	History and Status
Texaco Gasification (Texaco Development Company)	Fluidized bed, single-stage, partial oxidation	2,400°F 850 psig (can operate from 260-1,200 psig)	Texaco developed its gasification process from its commercially proven noncatalytic partial oxidation process to convert oil to synthesis gas from which hydrogen is produced. Texaco proved the feasibility of processing water-coal slurries in a 15 ton/day pilot plant in Montebello, California, which operates at 2,300°F and 350 psig. A plant processing 160 ton/day of coal is operational in West Germany. The Texaco process is to be used to produce 1,000 ton/day of ammonia from coal. The process operates at high pressure, can gasify any type and rank of coal, can gasify water-coal slurries as delivered, and produces no troublesome by-products.
U-Gas (Institute of Gas Technology)	Fluidized bed Caking coals pretreated at 700 to 800°F, ash is agglomerated into large particles for selective removal from the bed, fines returned to bed via cyclones	1,900°F 300-350 psig	Work on the fluidized-bed gasification of coal began in 1943. Originally, the process was designed to produce low-Btu gas as a complement to the HYGAS process. By changing the fluidizing medium from steam and air to steam and oxygen, a medium-Btu gas can be produced, capable of being converted to SNG by methanation. Tests in a steam-air blown 485 lb/hr unit demonstrated the suitability of the process for both combined-cycle power generation and as a "grass roots" source of industrial power generation energy. DOE has contracted for the design of a plant using the U-Gas process to produce 175 million scf/day of 300 Btu/scf fuel gas for industrial parks, from 2,800 ton/day of Kentucky No. 9 coal. The preliminary design is to be completed by April 1979. A unit has been operating at approximately atmospheric pressure to test ash agglomerating characteristics. Tests have been run on noncaking and caking coals at lower temperatures than usual. Results have been inconclusive, and the project has been delayed.
COMMERCIALLY AVAILABLE			
Koppers-Totzek (Heinrich Koppers GmbH in W. Germany and Koppers Company)	Entrained bed	3,300°F 5-7 psig	There are 16 plants in Europe and Asia, with 48 gasifiers in operation or under construction. In 1948, a 36 ton/day gasifier was built for a BOM coal-to-oil demonstration plant in Louisiana, Missouri. Koppers is presently negotiating with some eight U.S. companies for coal-based ammonia plants. A 1,000 metric ton/day ammonia plant was brought on stream in South Africa in December 1974, and three additional plants each designed with three gasifiers have been built in India.

Table 4-9. COAL GASIFICATION PROCESSES (CONT'D)

Process (Owner)	Process Type	Temperature and Pressure	History and Status
Lurgi Pressure Gasification (Lurgi Gesellschaft fur Warme-und Chemotechnik Mbttm W. Germany)	Fixed bed	1,140-1,400°F 350-450 psig	The Lurgi process is based on 40 years of continuous development and the experience of 14 commercial plants (65 gasifiers are operating in various parts of the world, including the plant at Sasolburg, South Africa, which has been operating since 1954 and handles 6,500 ton/day of coal).
Stoic (Stoic Combustion Ltd., Johannesburg, South Africa, and Foster Wheeler Corporation)	Two-stage fixed bed	Atmospheric pressure	DOE awarded a 5-year cost-sharing contract to operate a 72 ton/day gasifier located at Duluth, Minnesota, to produce 180 Btu gas for firing a boiler for heating/cooling campus buildings. The process will produce fuel oil as a coproduct, which will be used as a boiler fuel during gasifier maintenance.
Wellman-Galusha (McDowell-Wellman Company and Wellman-Galusha Company)	Fixed bed, with revolving grate, either air-blown (low-Btu), or oxygen blown (medium-Btu)	1,000-1,200°F Atmospheric pressure	The process has been commercial for over 30 years. Two units operating in the United States serve large industrial plants. The feasibility of constructing a fixed-bed gasifier for operation on caking coals is being studied. Projects sponsored by DOE using Wellman-Galusha gasifiers include (1) two 24 ton/day gasifiers to fire a brick kiln; (2) two 36 ton/day gasifiers serving a residential area, a shopping center, and municipal buildings; and (3) two gasifiers for space-heating an industrial park.
Wellman-Incandescent (Applied Technology Corporation is U.S. Licensee)	Two-stage fixed bed	1,800-2,200°F Atmospheric pressure	Two projects to demonstrate the use of these gasifiers in industrial processes are under way. DOE and the Land O' Lakes Creamery in Minneapolis, Minnesota, are sharing the $6.5 million cost of a 5-year project to design, construct, and operate a 72 ton/day gasifier. The Caterpillar Tractor Company announced plans in April 1977 to construct two Wellman-Incandescent coal gasifiers to produce clean, low-sulfur fuel gas to fire various heat-treating furnaces.
Winkler (Davy Powergas, Inc.)	Fluidized bed	1,500-1,800°F Atmospheric pressure	The process has been in use commercially at 16 plants in a number of countries since its development in Europe 50 years ago. The plants produce low-Btu fuel gas and synthesis gas. A high-pressure (200 psig) modification of the Winkler process, which should increase thermal efficiency, is being developed.

Table 4-9. COAL GASIFICATION PROCESSES (CONT'D)

Process (Owner)	Process Type	Temperature and Pressure	History and Status
Woodall-Duckman (Woodall-Duckman Ltd., England)	Two-stage fixed bed	1,800-2,200°F Atmospheric pressure	Originally developed in Italy in the 1940s, this process has been in use in Europe and South Africa for producing clean industrial fuel gas. The largest gasifier handles 100 to 120 ton/day of coal. DOE has awarded a contract to design, construct, and operate two 10 ft diameter gasifiers to treat 90 tons of low-sulfur coal. The gas is to be used to fire existing kilns.

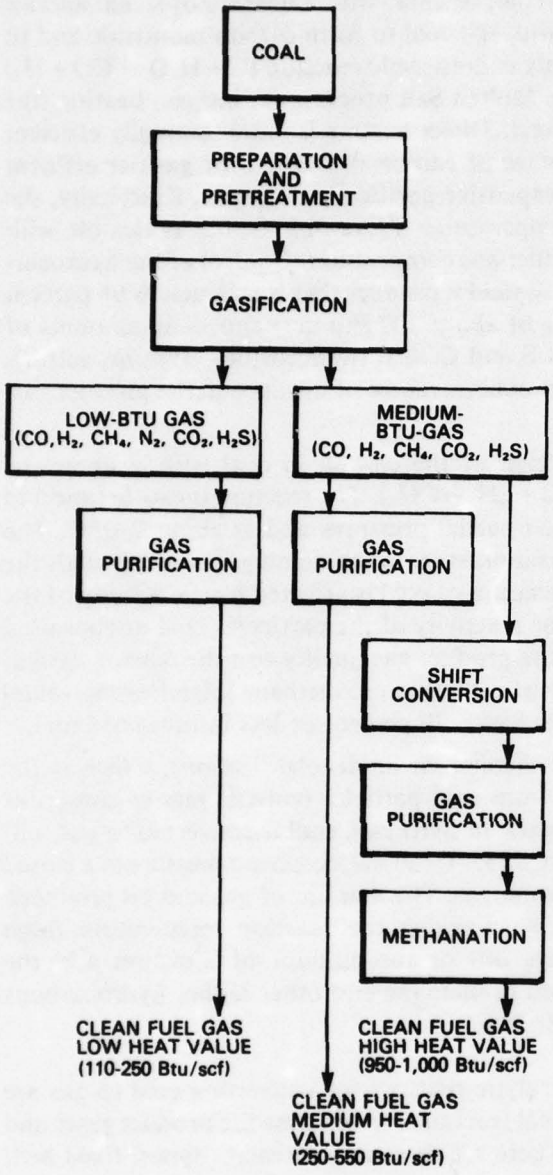


Figure 4-17. FUEL GAS FROM COAL

Pretreatment

Some gasifiers and processes are designed to handle all types and ranks of coal. For these, the pretreatment step is unnecessary and the prepared coal is ready for gasification.

If a caking or agglomerating coal is to be used in the gasifier, a pretreatment step is necessary. (Lignite, which does not agglomerate, requires no pretreatment before the gasification step; certain gasifier reactor designs, such as the entrained-bed reactor, eliminate the need to pretreat bituminous coal.) Pretreatment of coal involves partial volatilization and oxidation of the coal particle surface with steam and oxygen. This reaction results in a loss of a significant amount of potentially valuable volatile matter in the coal.

There are essentially three types of pretreaters: fixed bed, free fall, and fluidized bed. In fixed-bed pretreaters, the reaction temperature is about 425 °C and the pressure is 325 psig. The units are pressurized by the steam-oxygen mixture.

In free-fall pretreaters, the reaction temperature is 600 °C and the pressure is 300 psig. Coal is dropped through a countercurrent flow of steam containing 5 to 12 percent oxygen by volume; the residence time is approximately 2 seconds. The oxygen-to-coal ratio is about 2.4 scf/lb of coal. If the oxygen is insufficient or reaction temperature too low, the coal will agglomerate and plug the pretreater.

In fluidized-bed pretreaters, used to treat caking coal, oxygen mixes with steam or inert gases such as nitrogen and carbon dioxide. The reaction temperature is 375 to 415 °C.

Gasification

There are three ways in which coal can be converted to gas:

- *Gasification,* which is the reaction of coal, or char, with a mixture of steam and air or oxygen. The air or oxygen reacts with the coal to form carbon monoxide and to supply the heat necessary for the highly endothermic reaction ($C + H_2O \rightarrow CO + H_2$) to occur. Some processes, such as the Molten Salt process, use indirect heating (the molten salt) to supply the necessary heat. Direct heating is more thermally efficient than is indirect heating, but the presence of carbon dioxide in the gasifier effluent when heating is direct requires more expensive purification systems. Kinetically, the gasification reaction is favored at temperatures above 925°C, but is flexible with respect to operating pressure and product-gas composition. Control of the hydrocarbon, oxygen, and steam feed rates may yield a product that is as much as 96 percent H_2 by volume plus CO (heating value of about 300 Btu/scf) and small amounts of CO_2, CH_4, N_2, and Ar (with some H_2S and COS if the feedstock contains sulfur). With air as the oxidant, there is a large concentration of nitrogen in the product gas, resulting in low-Btu gas.
- *Hydrogasification,* which is the reaction of the carbon in coal with a stream of hydrogen-rich gas to form methane ($C + 2H_2 \rightarrow CH_4$). The reaction is exothermic and is favored kinetically at high hydrogen partial pressures and at about 730°C. The coal particles go through a devolatilization stage when coming in contact with the hot gases in the reactor unit. Hydrogenation of coal is affected by the activity of the char produced by devolatilization. The reactivity of the particular coal or char used will also have a significant effect on the product gas quality and the reactor design. In hydrogasification reactors, the rate of conversion to methane (high heating value) is typically above 90 percent, compared with 70 percent or less in other reactors.
- *Pyrolysis* (also known as destructive distillation or devolatilization), which is the vaporizing of volatile hydrocarbons from coal particles (volatile matter comprises more than 35 percent of the coal weight). In pyrolysis, coal is converted to gas, oil, char, and tar at high temperatures (above 535°C) and atmospheric pressure in a closed system with an oxygen-deficient environment. The amount of gas and oil produced by pyrolysis can be varied simply by changing the reaction temperature (high temperatures yield more gas and less oil) or the amount of moisture and the residence time. The product gas is rich in methane and other higher hydrocarbons with a heating value of 475 to 560 Btu/scf.

Gasification, hydrogasification, and pyrolytic reactors for converting coal to gas are designed to control the mixing between chemical reactants, to separate the product gases and by-products, and to regulate temperatures. There are three major reactor types: fixed bed, fluidized bed, and entrained bed.

In a fixed-bed reactor (see Figure 4-18), the gas velocity is relatively low and the solid particles remain stationary. A metallic grid or grate, generally mounted a short distance above the bottom of the reactor, supports the coal, which is fed into the top of the reactor. A rotating grate promotes an even distribution of the reacting gases and provides a means of drawing off the bottom of the bed. In dry ash gasifiers, which generally operate at 980°C, the ash is removed in solid form. The flow of solids countercurrent to the gasification medium leads to maximum heat economy and high thermal efficiencies of 70 to 85 percent for the production of cold, clean gas. Slagging gasifiers, in which ash is removed in liquid form, operate with an ash zone temperature of approximately 1,650°C to melt the slag.

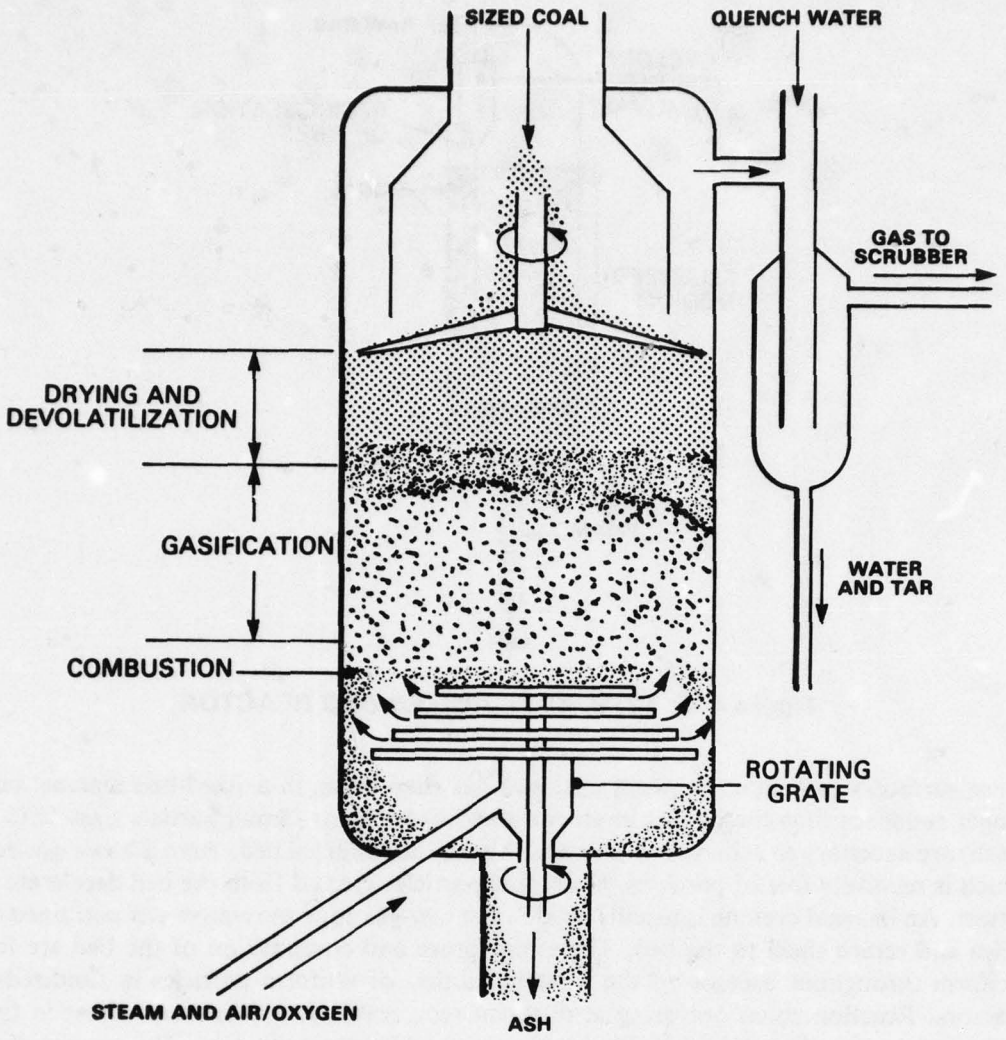


Figure 4-18. TYPICAL FIXED-BED REACTOR

Slagging permits the gasification of lump coal at higher temperatures and offers better steam decomposition and higher throughput than nonslagging. However, high reaction temperatures tend to aggravate refractory erosion caused by the molten slag. Only the slagging gasifier can handle caking coals without pretreatment. Among the processes using a fixed-bed are the Lurgi, Gegas-D, and Wellman-Galusha.

In the fluidized-bed reactor (Figure 4-19), air or oxygen and steam enter at the base of the reactor and are forced up under pressure through the fine grid distributor plate that supports the pulverized or pretreated coal. Above the distributor plate, the gaseous medium passes between bed particles forcing them apart and opening larger flow pathways. The downward gravitational force on the particles becomes balanced by the upward drag force on the particles by the gaseous stream, thus producing a "boiling" effect, which provides

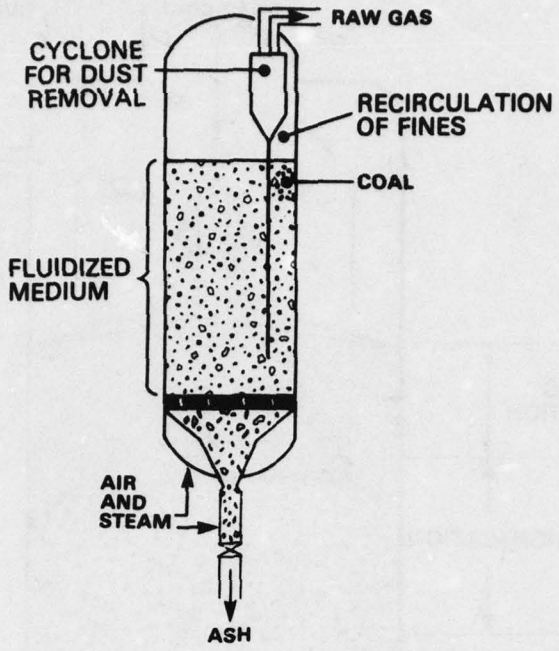


Figure 4-19. TYPICAL FLUIDIZED-BED REACTOR

more surface-area contact between coal and gas than exists in a fixed-bed reactor, and a longer residence time than exists in an entrained-bed reactor. Small particle sizes (8 to 100 mesh) are necessary to achieve this balance. Above the fluidized bed, there is a raw-gas zone, which is relatively free of particles. Here, fine particles ejected from the bed decelerate and return. An internal cyclone is usually used in the raw-gas zone to remove any entrained particles and return them to the bed. The temperature and composition of the bed are fairly uniform throughout because of the random motion of uniform particles in fluidized-bed reactors. Reaction zones operating at different temperatures, analogous to those in fixed-bed reactors, may be established by using a series of fluidized reactors. The temperature in the bed must be kept below the fusion temperature of the ash, which precludes the use of caking coals without pretreatment, and which results in higher carbon loss in the ash and lower thermal efficiency than the fixed-bed reactor. The Synthane, Winkler, and U-Gas processes use single-stage fluidized-bed reactors; CO_2 acceptor, HYGAS, and Hydrane processes use two-stage reactors.

Another type of fluidized-bed reactor is the molten bath reactor shown in Figure 4-20. The molten bath provides a well-mixed medium in which combustion and gasification occur simultaneously. The molten medium may be reactive, catalytic, or passive; it provides a way to transfer and store heat as well as to disperse the reactants. The reaction takes place above the melting temperature of the medium and above the slagging temperature of the ash. As a result, an ash-free product stream is generated. Limestone added to the melt will tend to absorb the sulfur from the coal. Sulfur can then be removed with the slag, resulting in a low-sulfur raw gas.

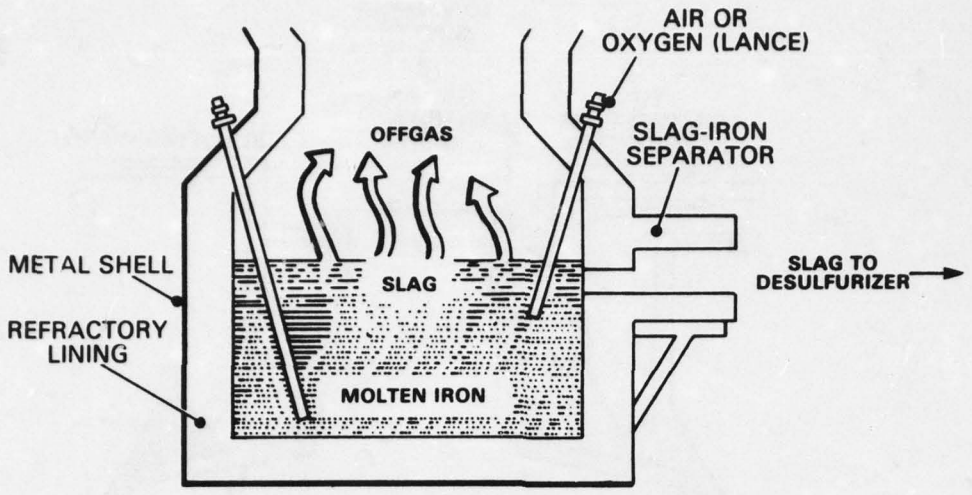


Figure 4-20. TYPICAL MOLTEN BATH REACTOR

The entrained-bed reactor (Figure 4-21) is characterized by very high gas-phase velocities and very small particle sizes (about 200 mesh). The drag force on the particles exceeds the gravity force, carrying the particles along with the gases. The reactants pass through the reaction zone for a short time, generally less than 10 seconds, but the very small size of the coal particles and high temperatures ensure a rapid reaction. Since all the reactants travel through the reaction zone at essentially the same velocity, the entrained flow gases are not mixed (as in the fluidized bed), but react sequentially as in a fixed-bed reactor. Relatively large quantities of oxygen are required to achieve high temperatures, roughly 1,800 °C, in the reactor and to achieve rapid reaction rates, low carbon loss in the ash, and ash slagging.

The difference between single- and two-stage processes is physical—location of the oxidant and steam injection point. A single-stage process results when the oxidant and steam are injected together. When the oxidant is injected upstream of the steam, two reaction stages result: combustion and gasification. The excess sensible heat in the product gas is used to generate process steam. This type of reactor, which can handle any type of coal without pretreatment, is used in the Koppers-Totzek, Texaco, BI-GAS, and other processes.

Shift Conversion

If the raw gas from the reactor is to be processed further to produce SNG, it must go through a shift converter. The major, slightly exothermic reaction is $CO + H_2O \rightarrow CO_2 + H_2$. The cooled gas (about 425 °C) from the gasifier is cleaned of dust and tar, then mixed with steam in the proper amount and passed over an iron-chromium oxide catalyst.

Gas Purification

Sulfur compounds must be removed from the gas before it can be burned as a clean fuel. If the gas is to be processed to form SNG, the carbon dioxide must also be removed.

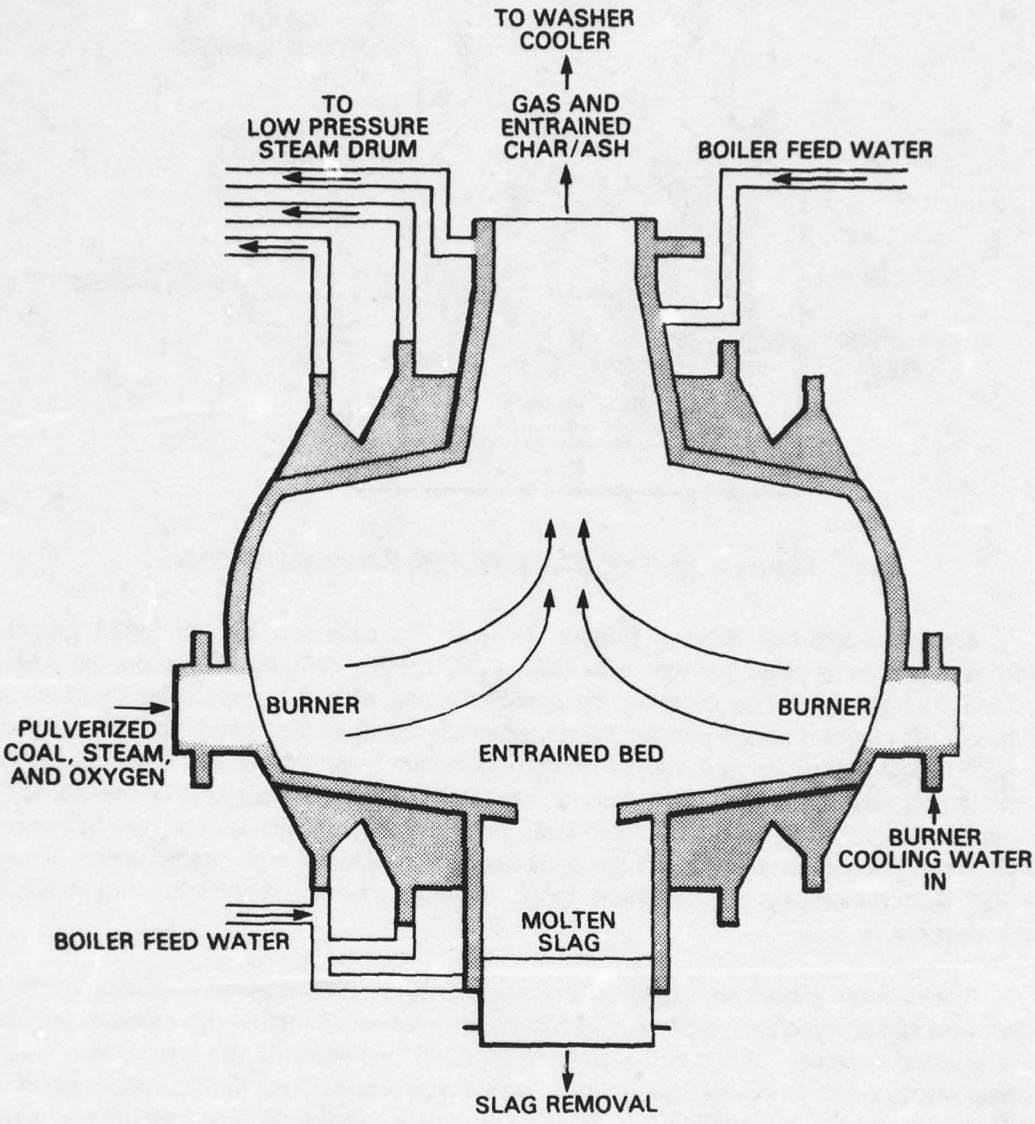


Figure 4-21. ENTRAINED-BED REACTOR

For low-and medium-Btu gas products, the purification step occurs immediately after gasification. If the gas is to be methanated, it is purified after shift conversion and before it enters the methanator, where sulfur compounds would poison the catalyst and carbon dioxide would interfere with the methanation process.

Several processes effectively remove acid gases (H_2S, CO_2, and COS) from a gas stream. They vary from a single once-through wash to complex multiple-step recycle systems. Generally, the final products are elemental sulfur and carbon dioxide; the absorbent is recycled.

Methanation

The last step in converting coal to high-Btu gas is methanation—the conversion of excess carbon monoxide and hydrogen into methane. The reaction taking place in the methanation unit is: $3H_2 + CO \rightarrow CH_4 + H_2O$. This is a highly exothermic reaction, and the method of removing heat from the reacting gas is the major problem in economic operation of methanators. The nickel or ruthenium catalysts used for methanation are easily poisoned by sulfur compounds; consequently, gases entering the methanator must be as pure as possible.

IN-SITU COAL GASIFICATION

Underground gasification is accomplished by drilling boreholes into the coal seam and injecting air (or steam and oxygen) into the underground reaction zone. The hot gases are forced through the seam to the exit borehole and carried to the surface to be cleaned and upgraded for use.

The idea of gasifying coal underground was first suggested by the British in 1868 and by the Russians in 1888. The Soviet Union began testing in-situ coal gasification in the early 1930s, and carried out major projects in the 1950s, reaching their peak of operations in the late 1960s; there are three underground gas plants still in operation, producing gas with a heating value of about 100 Btu/scf. The United Kingdom also conducted large-scale experiments in the 1950s. In the United States, the Bureau of Mines conducted tests during the 1940s and 1950s trying various techniques with generally inconclusive results. In 1968, Gulf Research and Development Company conducted tests in western Kentucky. Vertical wells were drilled from the surface; no preparation step was used. Gulf discovered that petroleum combustion techniques could be used to sustain combustion in the seam. The gas produced had a heating value of 270 Btu/scf, but no attempt was made to recover it.

Underground coal gasification offers a number of significant potential advantages, but some of these advantages have not yet been proved. DOE's in-situ gasification program is designed to show that, in addition to tripling our recoverable coal reserves, underground coal gasification minimizes health and safety problems associated with conventional coal extraction techniques since no mining is required. Furthermore, there is less surface disruption than with strip mining, less solid waste is brought to the surface, water consumption and atmospheric pollution are lower, and capital investment and gas costs are reduced by at least 25 percent. The primary disadvantages of underground coal gasification are possible contamination of surface water and underground aquifers and subsidence of the surface.

Because in-situ coal gasification could triple the economically recoverable coal reserve in the 48 contiguous states, DOE's goal is to develop at least one underground coal gasification technology to the stage of commercial application by the middle to late 1980s through joint government-industry efforts. The four major projects in the field, each testing a different concept, are Western Low-Btu Gas (linked vertical wells), Western Medium-Btu Gas (steam-oxygen packed-bed), Steeply Dipping Beds, and Eastern Coal Technology (longwall generator) projects.[28,29] A few privately funded projects are also under way.

The linked vertical wells process, which uses reverse combustion to advance a flame front against the flow of air to create a permeable linkage path for the flow of gas in the coal seam, successfully has produced up to 165 Btu/scf of gas for a 55 day period at a production rate up to 12 million scf/day.[30-34] The packed-bed process, which is designed for deep, thick (more than 15 m) seams of western subbituminous coals, uses steam and oxygen as the gasifying agent to produce a medium-Btu gas suitable for conversion to SNG or for use as a chemical feedstock; recently, during a 2 day period, production of 265 Btu/scf of gas at a rate of 1.7 million scf/day was demonstrated.[30,34-36] The objective of the Steeply Dipping Beds project is to assess technologies applicable to coals of various rank that are geographically scattered in the United States and currently unminable because the seams dip at angles greater than 35 degrees; the end product will be either low- or medium-Btu gas.[30,34,37] The longwall generator process uses directionally drilled wells placed horizontally in the coal seam with the ends intersected by vertical wells to produce gas from relatively deep, thin (1.5 to 4.5 m) eastern coal seams; initial tests are to provide data to determine well spacing for future tests.[30,34]

ENVIRONMENTAL ASPECTS OF COAL PRODUCTION TECHNOLOGY

Different steps in coal production technology cause various environmental problems, which are governed by laws listed in Appendix A as well as by earlier legislation.

Control technology to minimize coal-related environmental impacts still is being developed. In some cases, the economic feasibility of minimizing a specific environmental impact, coupled with the technical problems to be resolved, is a serious problem. Techniques presently available to control many of the environmental problems associated with coal technology are summarized in Table 4-10. Some of the environmental problems associated with mining, coal transportation, and utilization (direct combustion, liquefaction, and gasification) are discussed below.

Mining and Reclamation

Both surface and underground mining significantly affect the environment because they produce wastes that must be disposed of and involve operations that can affect water resources adversely. For example, surface mine spoils can produce acid runoff (acid mine drainage that occurs when coal-contaminated rainwater flows into water systems). Acid mine drainage is a serious problem in the eastern United States. Mining activities also can result in disturbance or dewatering of local groundwater aquifer systems.

Another important effect of surface mining on the environment is the altered configuration of the land, which often causes erosion, flooding, and landslides. Land disturbed by mining can be reclaimed (rehabilitated) so that it is productive and aesthetically acceptable. Land reclamation includes restoring the area to the original topography where possible, replacing the topsoil, and fertilizing and revegetating. (Revegetation may be a serious problem in the arid west because success is highly dependent on the amount of rainfall.) Contour mining causes a need for more reclamation on the downslope than does area mining, due to the piles of overburden, but there are several techniques for minimizing the

Table 4-10. ENVIRONMENTAL PROBLEMS AND CONTROL TECHNOLOGIES

Production Step	Problem	Control Technology
Mining		
Underground	Acid drainage	Contain/neutralize
	Solid waste	Well-managed landfill
Surface	Runoff solids	Control/treatment of runoff
	Acid drainage	
	Sediments	
	Air particles	
	Solid waste	Well-managed mine restoration and revegetation
Beneficiation	Air particles	Dust control
	High-sulfur solid waste	Recover sulfur
	Runoff solids	Contain
	Acid drainage	Contain/neutralize
Direct combustion		
Power plants (conventional)	Sulfur oxides	Scrubbers, fluidized-bed, clean coal
	Nitrogen oxides	Combustion modification, scrubbers, flue gas treatment
	Fly ash and smoke particles	Cyclones, baghouses, electrostatic precipitators, scrubbers
	Solid waste (ash)	Well-managed landfill
	Waste heat	Cooling/reuse
Industry	Sulfur oxides	Fluidized-bed, clean coal, scrubbers
	Nitrogen oxides	Combustion modification
	Fly ash and smoke particles	Electrostatic precipitators, baghouses, cyclones, scrubbers
	Solid waste (ash)	Landfill
	Waste heat	Cooling/reuse
Commercial/residential	Sulfur oxides	Low-sulfur fuel
	Nitrogen oxides	Combustion modification
	Fly ash and air particles	Electrostatic precipitators
	Solid waste (ash)	Landfill
	Waste heat	Cooling/reuse
Liquefaction and gasification	Runoff solids	Physical-chemical treatment
	Organic wastes	
	— Toxins	Physical-chemical/biochemical treatment
	— Carcinogens	
	Solid waste	Landfill
	Waste heat	Cooling/reuse
	Fugitive/accidental release of toxins, carcinogens	Design to eliminate

Source: U.S. Department of Energy and U.S. Environmental Protection Agency, "Energy/Environment Fact Book," March 1978.

impacts produced by the spoilbanks. According to the Surface Mining Control and Reclamation Act, lands cannot be mined unless they can be reclaimed.

Federal programs to study the technologies and problems related to reclamation have been expanded recently. DOE is identifying and evaluating the environmental effects of different types of surface mining techniques and related processes, and examining techniques to mitigate the adverse environmental effects of surface mining.[12]

Another environmental consideration of special importance in the western United

States is the preservation of alluvial valley floors—downstream valleys fed by surface or near-surface streams. These alluvial floors are recharged by drainage patterns that are easily disturbed by mining operations, resulting in decreased water supplies for farming and ranching in the area. The Surface Mining Control and Reclamation Act of 1977 (P.L. 95-87) protects these valleys.[11]

Underground mining produces fewer surface problems than does surface mining, but the materials resulting from mine drainage and cleaning coal at the surface must be treated and disposed. If not treated, they may be dissolved by rainwater, producing acid mine drainage. Other problems associated with underground mining include subsidence of the surface overlying the mines (greater with the longwall method than with room-and-pillar mining), and the accumulation of waste piles composed of excess materials, coal-separated materials, and refuse such as tailings and slag.[12]

Transportation

Transporting coal may cause several environmental problems. Both rail and slurry pipelines can have detrimental effects on natural habitats and communities. Coal-hauling trains cause noise pollution as well as traffic, land-use, and community disruptions. Slurry pipelines require large quantities of water, which might cause serious environmental problems, especially at points of origin in the arid west, and effluent disposal must be arranged at the receiving end.

Utilization

Burning coal directly to produce heat or steam for generating electricity, converting coal to gas or liquid, and manufacturing chemicals from coal all cause environmental problems, generally in the form of air and water pollutants, as well as land pollutants. Many of the pollutants resulting from the use of coal are toxic, carcinogenic, mutagenic, or teratogenic. Coal pollutants are being studied in detail; the feasibility of proposed coal utilization methods may depend on the findings of these investigations.

Air Pollutants

The combustion of coal produces three major types of air pollutants: sulfur oxides (SO_x), nitrogen oxides (NO_x), and particulates. Different types and quantities of these pollutants are produced depending on the type of coal burned, the boiler design, and the boiler operating conditions. In the United States, fossil-fueled power plants produce about 24 percent of the annual particulate emissions, 65 percent of the sulfur oxides, and 29 percent of the nitrogen oxides. About two-thirds of these pollutants come from coal-fired plants.[13] Because coal conversion processes could cause major deterioration in air quality, controls beyond best available control technology would be required, restricting the siting of some liquefaction and gasification plants. The Clean Air Act Amendments of 1977 provide for establishing air quality standards in the United States.

Sulfur Oxides

The amount of SO_x emitted depends on the type and the quantity of coal burned. Currently, SO_x emissions are reduced by using low-sulfur coals, cleaning the coal to remove inorganic sulfur before it is burned, or removing the pollutants from the stack gas (flue gas desulfurization) after combustion. The benefits of using low-sulfur coals are partially offset because these coals have lower heat content and therefore more coal must be burned to produce the same amount of power. Cleaning—beneficiation—also causes environmental problems (for example, sludges from coal preparation plants contain hazardous pollutants such as trace elements); techniques to solidify and dispose of these wastes are being developed.[39] Because of these problems, flue gas desulfurization is the primary method used to remove sulfur compounds.

Flue gas desulfurization uses a chemical (wet) scrubbing system, either a disposable (throwaway) or regenerable (product recovery and chemical reuse) type. Since product recovery is expensive, most of the flue gas desulfurization processes used commercially are of the "throwaway" type using lime and limestone.[10,19] Table 4-11 summarizes the more widely used processes. The federal government has supported extensive research in flue gas desulfurization, including development/demonstration projects directed toward improving the performance and economics of lime and limestone flue gas desulfurization. Regenerable flue gas desulfurization processes and processes capable of removing both SO_x and NO_x are also being investigated.[40]

Table 4-11. MAJOR FLUE GAS DESULFURIZATION PROCESSES

Process	Reagent	End Product	Principle of Operation	SO_2 Removal Efficiency (Percent)
Limestone scrubbing	Limestone	$CaSO_3/CaSO_4$ Sludge	Limestone slurry reacts in scrubber absorbing SO_2 and producing insoluble sludge	80-90
Lime scrubbing	Lime	$CaSO_3/CaSO_4$ Sludge	Lime slurry reacts in scrubber absorbing SO_2 and producing insoluble sludge	85-95
Wellman-Lord	Sodium carbonate (regenerated)	Sulfuric acid Sulfur	Soluble sodium sulfite absorbs SO_2 in scrubber; the sodium bisulfite produced is thermally regenerated yielding sodium sulfite and SO_2 for either acid or sulfur production	85-95
Double alkali	Sodium carbonate (regenerated) Lime	$CaSO_3/CaSO_4$ Sludge	Soluble sodium sulfite absorbs SO_2 in scrubber; the sodium bisulfite produced is reacted with lime precipitating $CaSO_3/CaSO_4$	85-95
Magnesium oxide	Magnesium oxide (regenerated)	Sulfuric acid	Magnesium oxide slurry absorbs SO_2 in scrubber; the magnesium sulfite produced is thermally treated yielding MgO and SO_2 for acid production	85-95

Source: Frank T. Princiotta, "Sulfur Control for Coal Combustion," *Energy Technology IV: Confronting Reality,* Proceedings of the Fourth Energy Technology Conference, 14-16 March 1977, Washington, D.C.

Nitrogen Oxides

NO_x emissions can be reduced by altering boiler design and operation to control the temperature of combustion. (Wet scrubbing processes can be used for removing NO_x, but they are prohibitively expensive.) Combustion temperatures can be reduced by reducing the excess air or recirculating the flue gas. Current research focuses on developing effective techniques for combustion modification. Postcombustion treatment for NO_x is also being pursued in conjunction with research in Japan (where NO_x standards are more stringent) as a second approach in case combustion modification cannot meet changing requirements.[40]

Particulates

Particulates are microscopic pieces of solids (for example, fly ash particles) emitted in the stack gas along with SO_x and NO_x. Their emission from pulverized coal-firing systems is twice that from cyclone furnaces. There are several ways to control the emission of particulates from the stack, including the use of electrostatic precipitators and wet scrubbers.

Electrostatic precipitators impose a very high electric field between a series of wires and tubes (or wires and plates), so that a low-current electrical discharge occurs between them. If the particulates can be ionized, they will respond to this field and be drawn to the tubes. If not, charged ions from the air will settle on the particles, making the particles behave as if they are ionized. The tubes are rapped periodically and the dust is collected in bins below the precipitators. Performance of a precipitator depends strongly on the amount of sulfur in the dust. Also, the efficiency of electrostatic precipitators depends on the stack gas temperature. Thus, it is necessary to know the operating conditions before a specific precipitator design is selected. Most precipitators are designed to have removal efficiencies of 92 to 99 percent,[10] and generally can remove 99.9 percent of the particles with diameters 3 microns or larger. However, the fine particles that escape are currently of concern because:

- They are the principal carriers of toxic and carcinogenic trace metals.[38]
- They are more easily inhaled.
- Their greater surface area increases the reactive or absorptive capacity.
- Particles in the size range 0.1-1.0 micron scatter or absorb sunlight, lowering visibility.
- Increases in consumption of coal could significantly increase the amount of fine particles in the atmosphere.[38]

Research is focused on the removal of fine particles by agglomeration before collection, by duct geometries that will produce more uniform gas flow across the entire cross-sectional area of the precipitator, and by more effective waste disposal.

Some wet scrubbers can be used to remove particles as well as gaseous pollutants, although there are waste disposal and water requirement problems associated with their use. Filtration systems such as baghouses, which remove particulates by passing the gas through cloth bags, also can be used. Fabric filters are not widely used in power plants, primarily because of insufficient data on cost, reliability, and operation and maintenance requirements.[38]

Particulate levels or concentrations, are difficult to measure using available instruments. The monitoring instruments themselves alter the behavior of the particles and do not stand up well under the harsh environment of the stack.[38]

Water Pollutants

When coal is used to fire boilers, there are various waterborne wastes from boiler feedwater preparation, boiler blowdown, boiler tube cleaning, cooling tower blowdowns, ash transport, and miscellaneous sources such as leaks and spills. The major direct pollutant from coal combustion is the waterborne ash, which is sluiced from the boiler and discharged into surface water, usually settling ponds, where most of the ash sinks and can be removed. However, water soluble ash components and residual suspended solids also are discharged into navigable waters. As discussed earlier, water pollution also occurs whenever rainwater runoff reaches surface water.

Solid Wastes

The large volume of solid wastes produced by coal conversion processes include mineral residue, sludge from water treatment, baghouse filtrates, char, heavy tar residues, and process reagents. After pollutants are collected with scrubbers, precipitators, and other systems, the resultant solid wastes, as well as slag and bottom ash from boiler operations, must be disposed of. The contaminating potential of toxic elements in solid wastes is of concern. In particular, waste components such as arsenic, mercury, selenium, sulfates, nitrates, and hydrocarbons could leach into water supplies. The solid residual produced in a fluidized-bed combustion system is of particular concern. Spent sorbent (mainly calcium sulfate) is discharged at the rate of about 1 ton of sorbent for every 4 tons of combusted coal. Ash is also a major volume solid waste. Massive quantities of coal ash also must be disposed of; the most common method used is land disposal, although a potential environmental problem occurs when water soluble components in the landfill leach into surface and groundwater systems. The Resource Conservation and Recovery Act of 1976 mandates that solid waste residues must be discarded in an environmentally acceptable manner to avoid problems from leaching, dusting, runoff, and air and water pollution.

HEALTH AND SAFETY ASPECTS

The health and safety of U.S. miners is primarily the responsibility of each state, with BOM having overall responsibility. BOM interferes only when state regulations and enforcement do not meet the requirements of the federal code.[41] Historically, the states have been protective of their prerogatives in this area; BOM officers were not allowed to enter a mine until 1941, when they were invited to become involved after a disaster. BOM was not given the right to close a coal mine for dangerous practices until 1952. In 1969, Congress passed the Federal Coal Mine Health and Safety Act in an effort to reduce deaths, disabling injuries, and disease incurred in coal mining. This act prescribed interim mandatory health and safety standards applicable to all underground coal mines until the Secretary of the Interior promulgated standards. The maximum amount of dust that should be inhaled, the amount of dust that may be emitted from drilling operations, the permissible amount of

noise, and the frequency at which chest x-rays must be given to each miner (at the operator's expense) are among the standards. Health and safety standards for underground mines (published in the Code of Federal Regulations) became effective in 1970; health and safety standards for surface mines became effective in March 1972 and May 1971, respectively.[18]

The newly mandated health and safety standards, investigations related to health and safety, and technological improvements have resulted in a greatly improved safety record in coal mines. For example, development of horizontal roof strain indicators, microseismic fracture warning systems, polymeric roof bolts, and chemical impregnation techniques have contributed to a reduction in accidents in coal mines from failure of roofs, ribs, or face in mines.[2] Hazards in the electrical, mechanical, illumination, communication, and material handling areas have been reduced through the use of such advanced techniques as automatic mining, remote surveillance and communication systems, portable area illumination systems, and protective canopies for use on underground low-coal machines.

Another major danger in coal mines results from the nature of the coal itself. Coal contains volatile material and fixed carbon. If the ratio of the volatile material to the volatile material plus fixed carbon exceeds 0.12, the coal dust can explode when ignited. Coal gas also is a major danger in coal mines; when the methane in the gas reaches a concentration of 5 to 14 percent, it too may explode when ignited. Because gas is mobile, the ensuing fire or explosion could affect men in remote parts of the mine. Methods have been developed to reduce the chance of fires and explosions through extensive studies of ignition, flame propagation, fire detection and alarm, suppression and extinguishment, and methanometry (measurement of methane). Water infusion and degasification are among the specific techniques developed to reduce the concentration of methane.

Coal mining health research has involved extensive work on pneumoconiosis (black lung disease)—a respiratory ailment caused by inhaling coal dust. Under the Occupational Safety and Health Act of 1970, miners are afforded an opportunity to have chest x-rays and other tests necessary to detect pneumoconiosis. Efforts to control coal dust include water infusion of coal beds and use of foaming systems on mining equipment and conveyor belts.

ECONOMICS

Coal market prices, as quoted in dollars per ton, vary considerably from region to region. These variations are attributable to varying production costs of different mining methods and to the differing chemical properties of the coal. Low-sulfur and high-Btu coals extract premiums for the advantages they offer the user. Prices also vary depending on whether the coal is sold on the contract or the spot market; compared with contract prices, spot prices tend to be higher in times of excess demand and lower in times of excess supply. Average FOB mine prices have risen slowly since 1974, to about $20.50/ton in 1977.

Mining and Reclamation

Prices required to support the production of coal (that is, prices that will cover mining costs and yield a specified discounted cash flow rate of return on investment) depend on

many economic and physical factors. Economic factors include unit costs of labor, capital, and intermediate inputs (operating and maintenance supplies, power, and services). Other indirect economic variables are the effective tax rate, depreciation, depletion, reclamation requirements, and proposed environmental regulations. Major physical factors include the average seam thickness, size of the mine, and depth of the overburden. Other physical conditions that affect the cost of mining are the type of overburden, which affects the cost of drilling, shooting of explosives, and removing the overburden at surface mines; the amount of methane gas present in underground mines, which affects ventilation costs; the average roof condition, which affects the cost of roof bolting and other support; and the average topography and local climate, which affect the selection of capital equipment and the method of reclamation.

Production costs, including depreciation, typically constitute 60 to 65 percent of the required selling price of coal.[33] Labor costs in underground mining constitute a higher percentage of the total costs than capital-related costs, while surface mines are more capital intensive. On a Btu basis, surface coal is typically much cheaper than underground coal.

Topsoil handling and reclamation can add up to 28 percent of the total cost of mining coal.[12] Table 4-12 shows that reclamation costs at selected surface mines ranged from $0.16 to $2.91/ton. Reclamation costs at underground mines range from $1.00 to $5.00/ton for areas damaged by subsidence, and average $1.50/ton.[8] Reclaiming areas damaged by acid mine drainage averages $0.60/ton.[9]

Table 4-12. SURFACE MINE RECLAMATION COSTS[a]

Activity	East (15 sites)		Central (9 sites)		West[b] (7 sites)	
	Cost/acre	Cost/ton	Cost/acre	Cost/ton	Cost/acre	Cost/ton
Premining engineering/ antipollution	$ 233	$ —	$ 710	$0.14	$ 555	$0.04
Permits and fees	46	0.01	30	—	35	—
Topsoil/overburden handling	7,324	2.78	4,048	0.73	2,043	0.12
Revegetation	274	0.12	93	0.02	173	—
Total	$7,877	$2.91	$4,881	$0.89	$2,806	$0.16

[a]The costs per acre are not in direct proportion to the costs per ton due to variances in coal seam thickness of the sample sites. Categories showing less than $0.01 are not included in the totals because they do not affect the totals when rounded.

[b]The western sites do not include irrigation costs in the revegetation estimate. One researcher estimated that this could increase the cost per acre by about $500.

Source: U.S. General Accounting Office, "U.S. Coal Development—Promises, Uncertainties," September 1977.

Transportation

The cost of transporting coal contributes significantly to the final delivery price of coal to the end user. Recent surveys and studies indicate that transportation costs range from 25

percent of the cost of coal delivered from eastern coal fields to as much as 75 percent or more of the delivered price of coal shipped from Montana and Wyoming to electric utilities in the midwestern states. Table 4-13 shows average rail transportation costs as a percentage of price.

Table 4-13. TRANSPORTATION COSTS

Year	Price/Ton FOB Mine	Average Rail Charge/Ton	Delivered Price/Ton	Transportation Share (Percent)
1974	$15.75	$4.71	$20.46	23
1975	19.23	5.23	24.46	21
1976	19.43	5.86	25.29	23
1977[a]	20.50	6.51	27.01	24

[a]Preliminary.

Source: U.S. Department of Energy, "Energy Data Reports," *Weekly Reporter,* 28 April 1978.

Of the three most prevalent modes of coal transport, barge hauling is the least costly (from $0.003 to $0.004/ton-mile), followed by rail ($0.01/ton-mile) and truck ($0.05/ton-mile).[18,42] An alternative mode of coal transport is by slurry pipeline; costs for transporting western coal would be comparable to rail costs, but the cost of generating electricity at the mine then shipping it with extra-high-voltage transmission lines would be about 50 percent higher.[43] The costs per million end-use Btu for several alternatives are presented in Table 4-14. Other studies indicate that, in some cases, slurry pipelines have cost advantages over unit trains.[16,44] Pipelines are characterized by economies of scale that promise large cost savings for coal delivered over long distances, but demand relatively high capital investment.

Table 4-14. WESTERN COAL/ENERGY TRANSPORTATION COSTS

Mode	Cost/Million End-Use Btu[a] (1975 Dollars)
Slurry pipeline/conversion to electricity	6.18
Unit train/conversion to electricity	6.23
Mine-mouth conversion to electricity/shipment by wire	8.20
Mine-mouth gasification/pipeline/conversion to electricity	11.28
Mine-mouth gasification/pipeline/direct-use	2.87

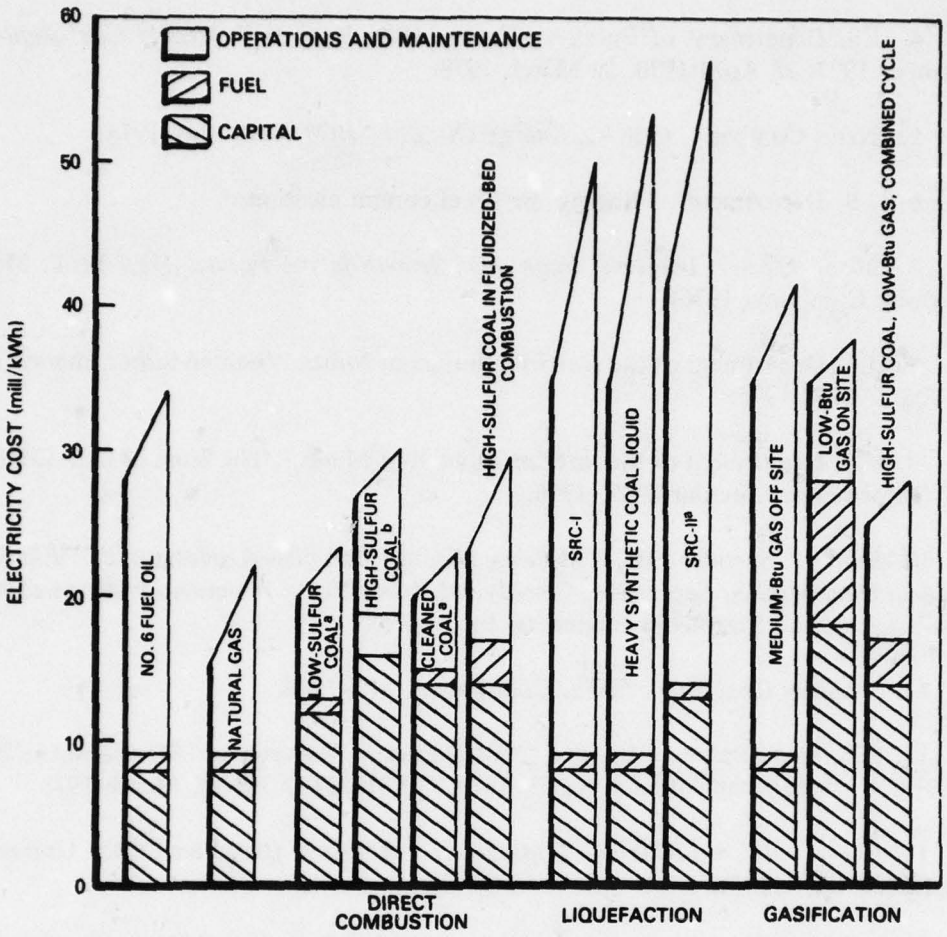
[a]Assuming all-equity financing.

Source: U.S. Department of the Interior, Bureau of Mines, "Comparison of Economics of Several Systems for Providing Coal-Based Energy to Users 1,000 Miles Southeasterly from Eastern Wyoming Coal Fields—Four Modes of Energy Transportation and Electricity Versus Gas as the End Use Energy Forms," 1975.

Utilization

The capital, operations and maintenance, and fuel costs of producing electricity by direct combustion, liquefaction, and gasification of coal are shown in Figure 4-26; the costs of producing electricity with No. 6 fuel oil and natural gas are also shown for comparison. The estimates shown are based on the assumptions that the plant has a capacity of 800 MW and operates at 70 percent capacity. A 10 percent discounted cash flow rate of return (in 1975 dollars) and a 15 percent project contingency are also assumed. As can be seen, many of the coal alternatives compare favorably with natural gas and No. 6 fuel oil.

Adding emission control equipment is expected to increase plant capital and operations and maintenance costs substantially—12 percent in capital costs and 33 percent in operations and maintenance costs—for new cost-fired plants meeting current New Source Performance Standards.[45] These increased costs generally are not offset by the lower costs of the high-sulfur coals, resulting in an overall increase in the cost to the consumer. For example, retrofitting a solid fuel electric utility plant will increase the cost 4 to 5 mill/kWh.



[a]Without flue gas desulfurization.

[b]With flue gas desulfurization.

Source: C. W. Knudson and P. O. Hedman, "Fossil Fuel Economics," *Economics of Coal Conversion Processing,* American Chemical Society, 1978.

Figure 4-22. COMPARATIVE COSTS OF PRODUCING ELECTRICITY IN 800 MW PLANT OPERATING AT 70 PERCENT CAPACITY

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5. OIL SHALE

Oil shale is a fine-grained sedimentary rock containing a brown to dark gray organic material called kerogen. Kerogen, a complex molecular substance, is composed mainly of carbon and hydrogen, with some nitrogen, oxygen, and sulfur. Heating oil shale to about 480°C pyrolyzes the kerogen into a viscous liquid called shale oil, plus some gas and solid coke. Because shale oil does not appear in nature as a liquid combustible substance and is the product of treating a natural material, shale oil is termed a "synthetic" crude oil.

Shale oil will compete in the petroleum market. After some initial treatment, or upgrading, crude shale oil can be used as refinery feedstock or boiler fuel. It is well suited for refining into middle distillate fuels, particularly jet and diesel fuels. The Department of Defense (DOD) considers shale-derived fuels an attractive alternative to petroleum products vital to military operations.[1] Additionally, shale oil can replace imported crude oil barrel for barrel and thus has the potential to reduce the U.S. balance of payment deficits.

OIL SHALE RESOURCES

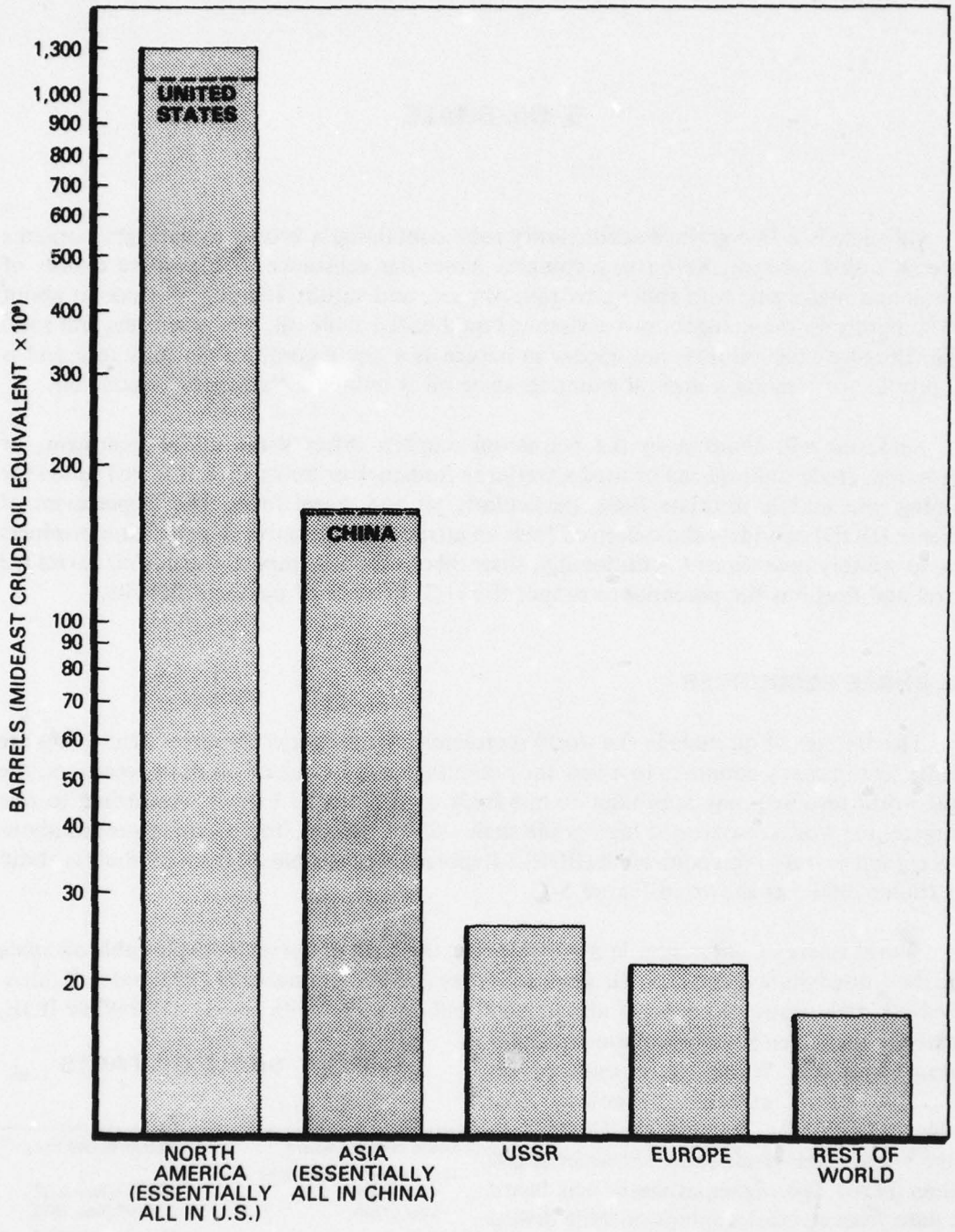
The amount of oil shale in the world represents a large energy resource. While data are insufficient in many countries to assess the potential energy value of oil shale resources, the total world resource may approximate hundreds of trillions of barrels. According to one estimate, the world resource of high-grade shale—25 to 100 gal./ton oil shale—totals about 16.9 trillion barrels of oil equivalent (BOE).[2] Reported recoverable oil from oil shale is about 1.5 trillion BOE, as shown in Figure 5-1.

World Energy Conference data indicate that the bulk of currently exploitable oil shale is in the United States. The U.S. Geological Survey (USGS) estimated in 1973 that U.S. identified oil shale resources contain about 2,000 billion BOE, with about 418 billion BOE, located in the Green River Formation in Colorado, Utah, and Wyoming, considered recoverable using current technology (see Tables 5-1 and 5-2).[3] In 1966, the USGS indicated known high-grade shale resources at 600 billion BOE. The higher estimate was based on data from coreholes (plugs of shale drilled out of deposits) and cuttings (chips of ore), and the lower estimate was based on corehole data only. USGS considers the latter method more reliable and the lower resource estimate, therefore, more accurate, but the higher resource estimate is still being used, based on information gained through preliminary oil

Table 5-1. SHALE OIL FACTS

Gross energy content	18,330-18,680 Btu/lb
U.S. identified resources	
High grade	418 billion BOE
Low grade	1,600 billion BOE
U.S. estimated resources	25,500 billion BOE
Concentration	10.5-75 gal./ton

Source: Cameron Engineers, Inc., "Synthetic Fuels Data Handbook," 1975, and U.S. Geological Survey, Professional Paper 820, 1973.



Source: World Energy Conference, *World Energy Resources 1985-2000* (New York: IPC Science and Technology Press, 1978).

Figure 5-1. REPORTED WORLD RECOVERABLE OIL SHALE

Table 5-2. U.S. OIL SHALE RESOURCES[a]

Deposit	Resource (billions of bbl)					
	Identified[b]		Hypothetical[c]		Speculative[d]	
	25-100[e] gal./ton	10-25 gal./ton	25-100 gal./ton	10-25 gal./ton	25-100 gal./ton	10-25 gal./ton
Green River Formation, Colorado, Utah, and Wyoming	418	1,400	50	600	–	–
Chattanooga shale and equivalent formations, central and eastern United States	–	200	–	800	–	–
Marine shale, Alaska	Small	Small	250	200	–	–
Other shale deposits	–	Small	NE	NE	600	23,000
Total	418	1,600	300	1,600	600	23,000

[a]All resource figures except those for the Green River Formation are adapted from Duncan and Swanson, in U.S. Geological Survey, Circular 523, 1965.

[b]Identified resources are specific, identified mineral deposits that may or may not be evaluated as to extent and grade, and whose contained minerals may or may not be profitably recoverable with existing technology and economic conditions.

[c]Hypothetical resources are undiscovered mineral deposits, whether of recoverable or subeconomic grade, that are geologically predictable as existing in known districts.

[d]Speculative resources are undiscovered mineral deposits, whether of recoverable or subeconomic grade, that may exist in unknown districts or in unrecognized or unconventional form.

[e]The 25-100 gal./ton category is considered virtually equivalent to the category "average of 30 or more gallons per ton."

NE: Not estimated.

Source: U.S. Geological Survey, Professional Paper 820, 1973.

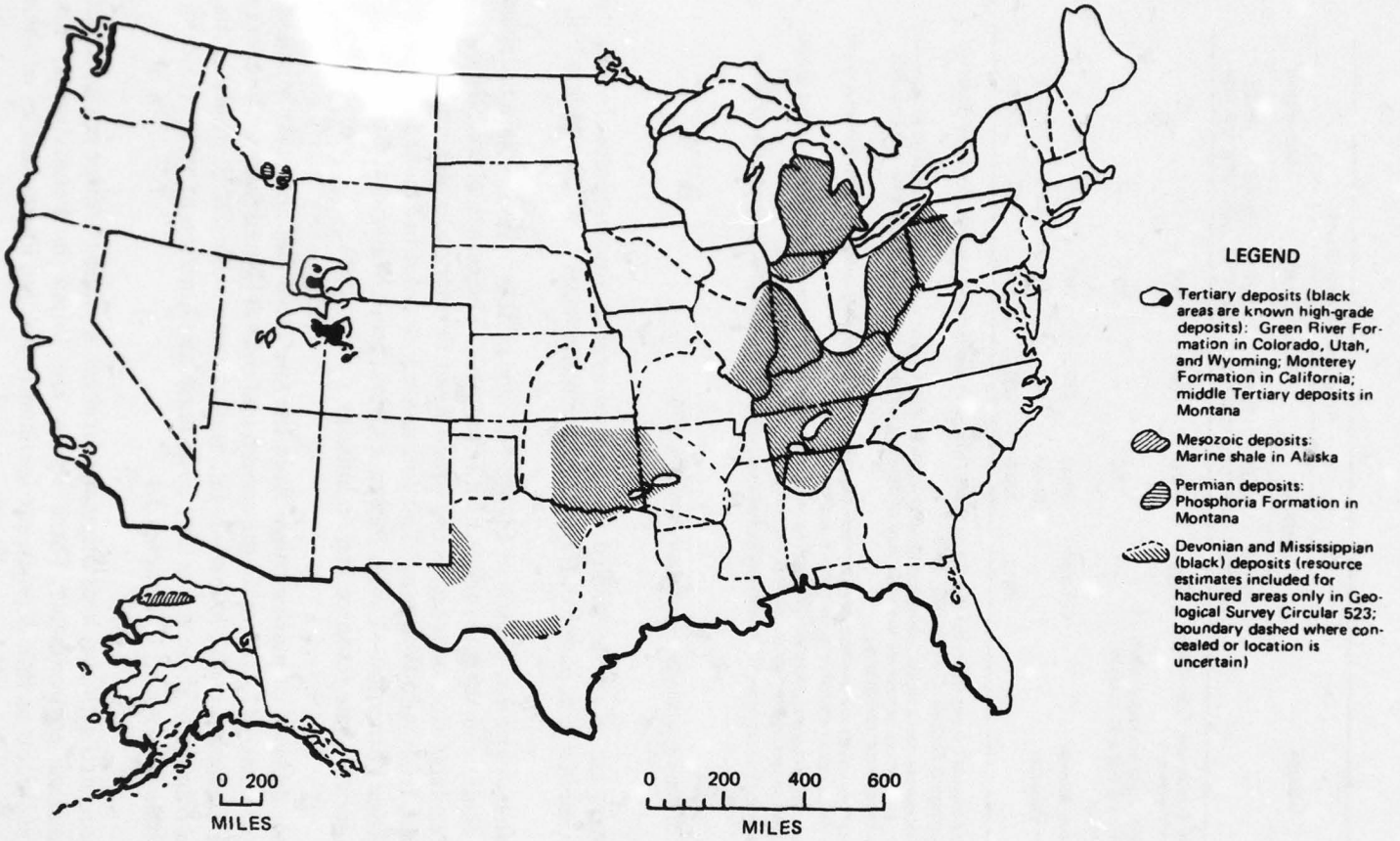
shale development and coreholes drilled for the prototype leasing program. In either case, the resource is massive compared with the U.S. petroleum reserve of 29.5 billion bbl.

U.S. oil shale deposits, shown in Figure 5-2, are of three types—shale in lacustrine rocks, marine shale, and shale associated with coal beds. The principal lacustrine deposit, formed from two large Eocene lakes, is the Green River Formation, which underlies 44,028 km^2 in Colorado, Utah, and Wyoming. This formation is detailed in Figure 5-3. Four basins of the Green River Formation—Uinta, Piceance Creek, Sand Wash, and Green River—are the sites of major oil shale resource and technology development.

Black shale deposits of marine origin from the late Devonian and early Mississippian age underlie more than 647,475 km^2 in the eastern and central United States. The average oil yield from the Devonian shales is low—5 gal./ton of shale[3]—but DOE estimates that the quantity of gas trapped in these shales may be as much as 37 m^3/ton of rock.[4] (Information on gas from shale is provided in Chapter 3.)

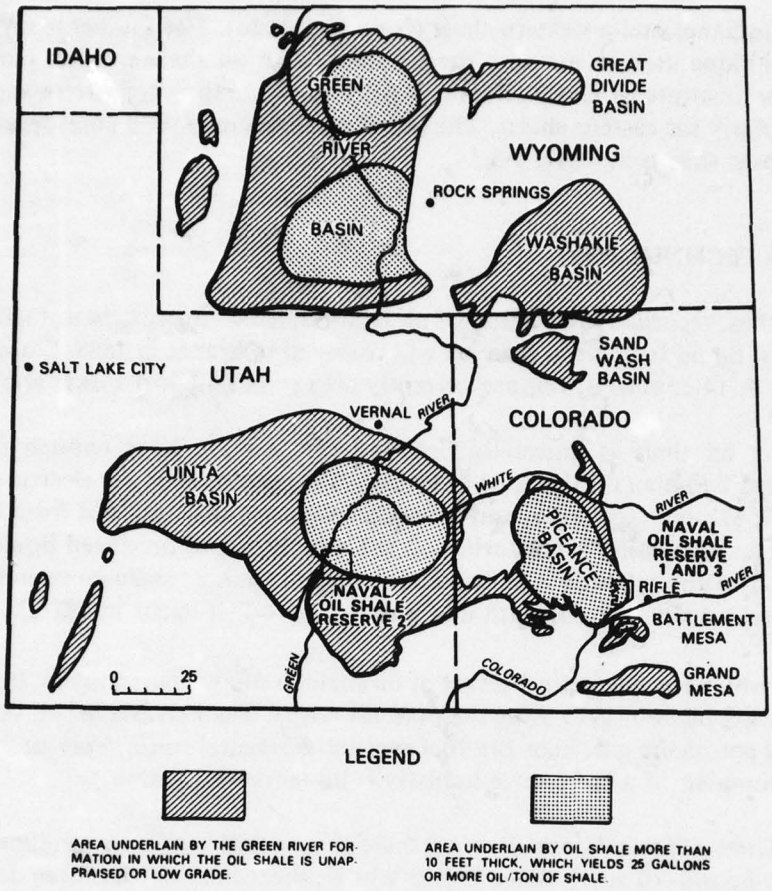
Shales associated with coal beds originated in either a shallow marine environment or a swampy nonmarine environment. These shales are found in Pennsylvania, Kansas, Oklahoma, and Illinois as thin deposits predominantly yielding low quantities of shale oil.

Table 5-3 shows the chemical composition and the Fischer assay yield of an eastern



Source: U.S. Department of the Interior, *Final Environmental Statement for the Prototype Oil Shale Leasing Program,* Vol. 1, 1973.

Figure 5-2. PRINCIPAL REPORTED OIL SHALE DEPOSITS IN THE UNITED STATES



Source: U.S. Geological Survey, Circular 523, 1965.

Figure 5-3. OIL SHALE DEPOSITS IN THE GREEN RIVER FORMATION

Table 5-3. COMPOSITION OF EASTERN AND WESTERN SHALES

Analysis	Eastern	Western
Ultimate (weight percent—dry basis)		
Organic carbon	13.7	13.6
Hydrogen	1.64	2.1
Sulfur	4.72	0.5
Carbon dioxide	0.5	15.9
Ash	78.3	66.8
Fischer Assay		
Oil yield (weight percent)	4.6	11.4
Water yield (weight percent)	2.3	1.6
Loss + gas (weight percent)	2.4	2.6
Assay (gal./ton)	10.3	29.8

Source: Institute of Gas Technology, "Process Shale to SNG," *Hydrocarbon Processing,* April 1977.

shale (from Indiana) and a western shale (from Colorado). The Fischer assay is a standard retorting technique used to measure the oil yield of an oil shale sample. However, recent studies by the Institute of Gas Technology (IGT) indicate that hydroretorting increases oil yield, particularly for eastern shales. Thus, eastern shales may yield considerably more than 10.3 gal./ton as shown in Table 5-3.[5]

OIL SHALE TECHNOLOGY

The earliest recorded production of oil from shale was in Austria in 1350, and the first production of liquid fuels from shale oil was recorded in France in 1838. Shale oil industries have existed in 14 countries, but are currently operating only in Estonia and Manchuria.[6]

Estonian oil shale is unusually rich and reserves are large enough to support an industry. Most Estonian oil shale, or kukersite, is burned directly for electric power generation. Fuel oil, gasoline, town gas, and some chemicals are also obtained from kukersite. The Japanese began exploiting Manchurian oil shale in 1926 and produced liquid fuels during World War II. Although little is known about current Chinese shale oil operations, shale oil production reportedly met one-fifth of China's oil product needs in 1974.[6]

Brazil, which has adequate reserves of oil shale to support an industry, began operating a demonstration plant in 1973 using the Petrosix retort. The Petrosix process produces shale oil, liquefied petroleum gas, high-Btu fuel gas, and elemental sulfur from Brazilian, or Irati, shale. Development of a large-scale industry is under consideration.[6]

In the United States, Green River oil shale alone could support a 1 million BOE/day industry for thousands of years. Since World War II, the technology has been developed to extract oil from shale and to produce synthetic liquid fuels from shale oil. Oil is obtained by mining the shale and heating it in surface retorts, or by retorting the shale in the ground.

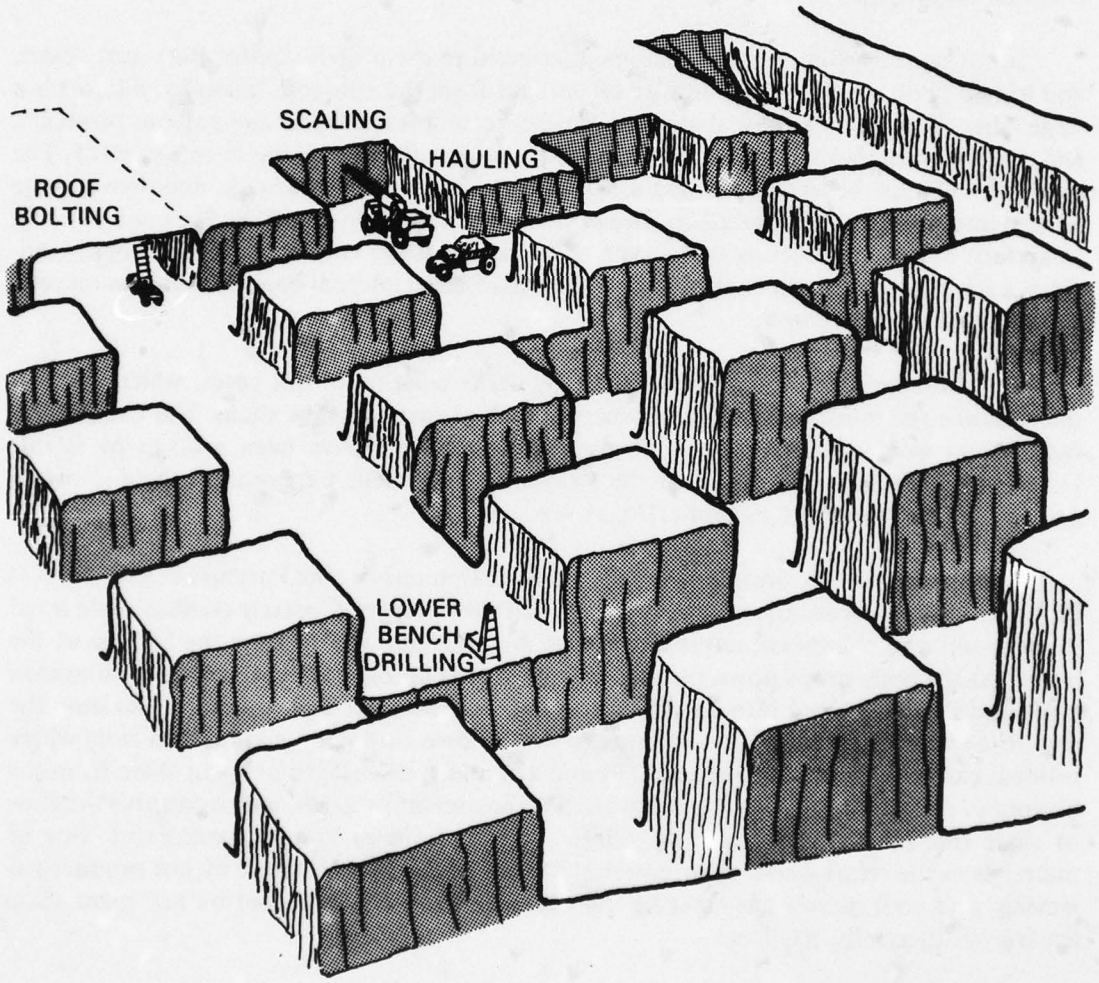
Mining

Both surface and underground mining techniques can be used to extract oil shale from the earth, and the shales of the Green River Formation are suited to either technology. Open-pit or strip-mining methods are used to recover shale from deposits near the surface. For open pit mining, the overburden is blasted loose, loaded onto trucks or a conveyor, and moved to a disposal site. The ore deposit then is blasted and the loose shale is loaded onto trucks or a conveyor and moved to a crushing unit. For strip mining, the overburden is removed by a dragline (a large power shovel) and dumped nearby. The shale deposit then is mined as in open-pit mining. Use of either of these surface mining technologies recovers almost 100 percent of the resource in the deposit.

Room-and-pillar mining is a proved underground mining technique for oil shale extraction. Drilling, blasting, loading, hauling, scaling, and roof bolting create underground rooms supported by pillars of ore. The shale is blasted and the loose shale is scooped up by 80-ton front-end loader trucks and hauled to a conveyor or crusher unit on the surface. Some shale purposely is left in place as pillars. The walls of the newly formed underground

rooms are scaled to remove loose shale, and roof bolts are installed to prevent ceiling collapse. This process is repeated to construct a series of rooms through the shale zone. (See Figure 5-4.) According to U.S. Bureau of Mines (BOM) research on room-and-pillar mining at the Anvil Points Experimental Station in Colorado, 18.3 m wide rooms with 18.3 m square pillars are safe for underground operations.[7] Room-and-pillar mining recovers about 60 percent of the resource; the rest remains as support pillars.

The choice of a particular mining technique is affected by the accessibility and extent of the shale deposit, amount of water in the deposit, topographical features, overburden



Source: Colorado School of Mines Research Institute, "A Practical Approach to Development of a Shale Oil Industry in the United States," October 1975.

Figure 5-4. COLONY DEVELOPMENT OIL SHALE MINE USING ROOM-AND-PILLAR TECHNIQUE

thickness, and other factors. For example, a stripping ratio approaching 2.5:1 favors underground mining over surface mining. (The stripping ratio is the ratio of the overburden thickness to the shale deposit thickness.) The stripping ratio of the thick shale deposits in the Piceance Basin is 0.5:1, indicating that those deposits are suitable for surface mining.[7] The thick shale beds exposed along the cliffs of the Basin are appropriate for underground mining, however, which causes less surface upheaval.

One shale oil plant with a capacity of 50,000 BOE/day will process at least 63,500 metric tons of 30-gal./ton shale each day, requiring a very large-scale mining effort. In fact, oil shale mines will be the largest mines in the world, creating logistics and environmental problems in establishing oil shale industries.

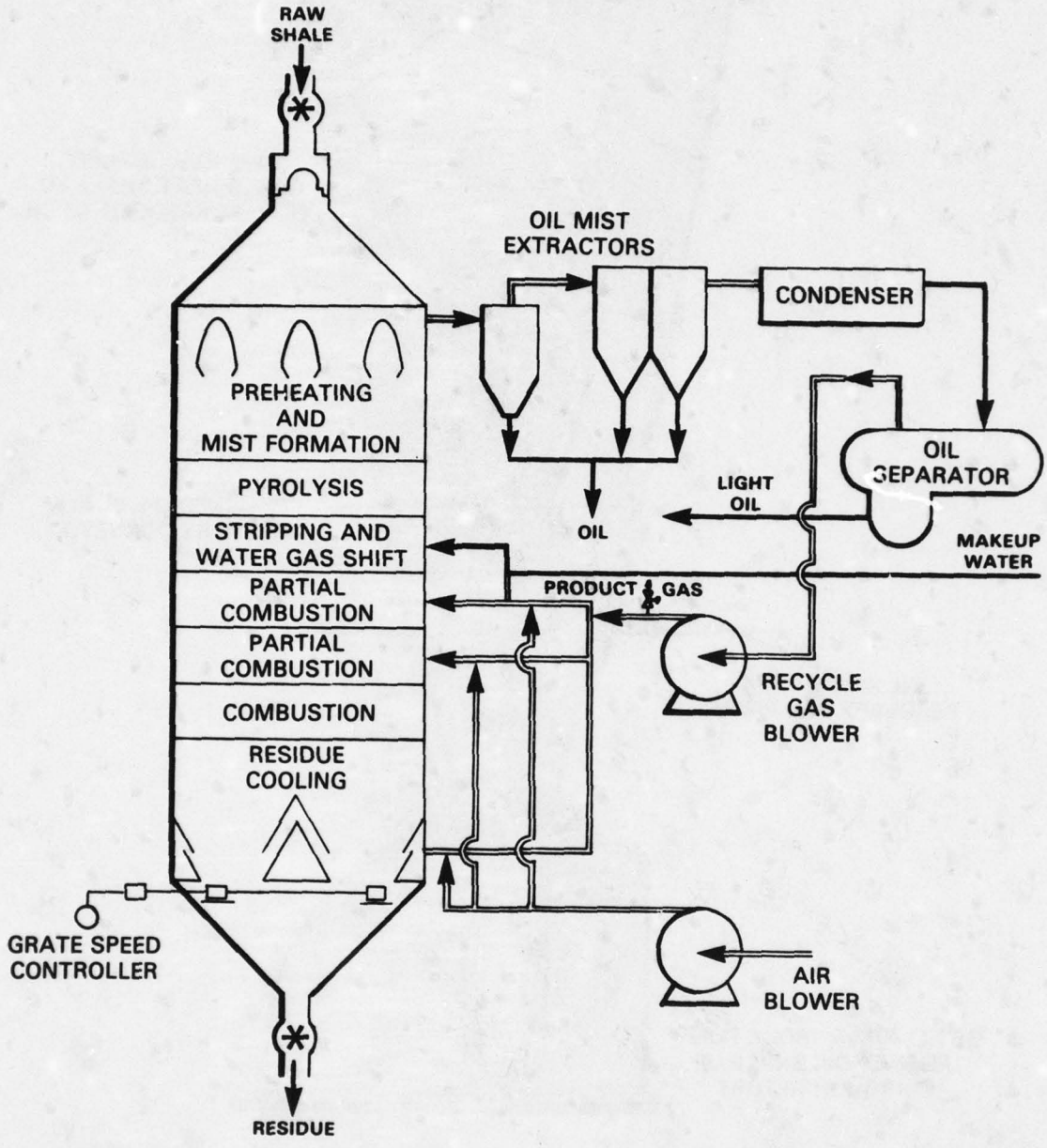
Surface Retorting[6,7]

In surface retorting, oil shale is mined, crushed to the proper size for the retort vessel, and heated to about 480°C to produce oil and gas from the kerogen. Basically, a retort is a large kiln equipped with a raw shale feeder, pipes to collect the liquid and gaseous products, and a mechanism to discharge the rock, or spent shale, after the oil has been extracted. The produced oil must be treated, or upgraded, to serve as refinery feedstock, and then may be refined into marketable oil products. Spent shale is deposited in landfills. The main variable in surface retorting processes is the type of heating method employed. Technologies considered for possible commercialization can be classified as internal-combustion, gas-recycle, or solid-heat-carrier retorts.

Internal-combustion retorts heat shale by the circulation of hot gases, which are produced inside the retort by the combustion of residual carbon in the shale. The earliest surface retorts were of this type. Contemporary descendents have been evolved by BOM, Development Engineering, Inc. (for the Paraho Development Corporation shale retorting project), and Union Oil Company (Union A).

BOM's retort is the prototype internal-combustion retort. The Paraho kiln (Figure 5-5) processes shale in essentially the same manner as BOM's retort. Coarsely crushed shale is fed into the top of a cylindrical retort and heated by gases moving up from the bottom of the retort. As the shale drops down through the retort, the kerogen is pyrolyzed by combustion gases and is transformed into an oily vapor that is drawn off with the hot gases near the top of the kiln. Retorted shale continues to move down through a combustion zone where residual carbon is ignited by recycled gas and air, and is discharged as spent shale from the bottom of the cylinder. A Paraho innovation is the oscillating grate, which controls the flow of shale through the retort and discharges the spent shale. The countercurrent flow of materials in the retort—cool shale entering the top of the kiln is heated by hot product gas leaving, and cool recycle gas entering the bottom of the kiln is heated by hot spent shale leaving—is thermally efficient.

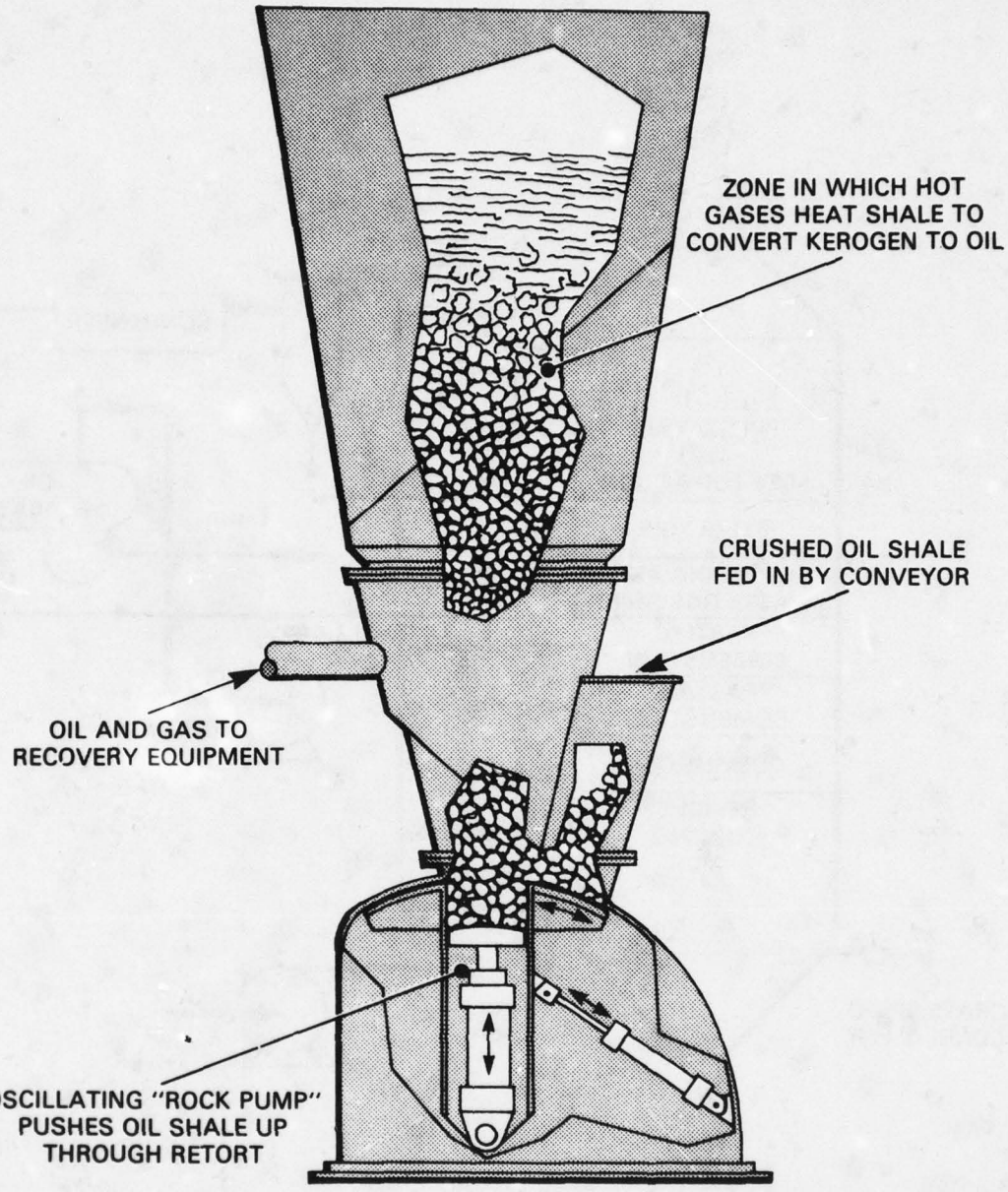
The Union A gas-combustion retort (Figure 5-6) reverses the Paraho process. Raw shale is fed into the bottom of the inverted-cone-shaped retort and pushed upward by a rock pump; the shale is retorted as it is advanced through the retort. The spent shale is discharged at the top, and product oil is extracted from the bottom of the retort.



Source: Cameron Engineers, Inc., "Oil Shale Seminar," 26-27 September 1977.

Figure 5-5. PARAHO RETORTING PROCESS

Gas-recycle retorts heat shale by the circulation of externally heated fluids. Gases enter the retort at temperatures high enough to pyrolyze kerogen, and leave the retort cooled. The gases are then reheated and recycled through the shale. No combustion occurs inside the retort. Union Oil Company has designed two gas-recycle processes—Union B and Union Steam Gas Recirculation (SGR). The Petrosix retort used in Brazil is also a gas-recycle retort.



Source: Colorado School of Mines Research Institute, "A Practical Approach to Development of a Shale Oil Industry in the United States," October 1975.

Figure 5-6. UNION A RETORTING PROCESS

The Union B gas-recycle retort is physically similar to the Union A retort; it has the inverted-cone shape and uses a rock pump to push shale up through the retort. The Union B process uses gas heated in a separate furnace to pyrolyze the shale. The hot gas enters the sealed retort vessel and heats the shale. The gas leaving the retort is cool, and is reheated externally. The Union SGR process (Figure 5-7) is more thermally efficient, using combustion of steam, air, and residual carbon in the spent shale to produce hot gases. Combustion takes place outside the retort and the hot gases are used as recycle gas for heating oil shale, and as product gas to increase fuel yield.

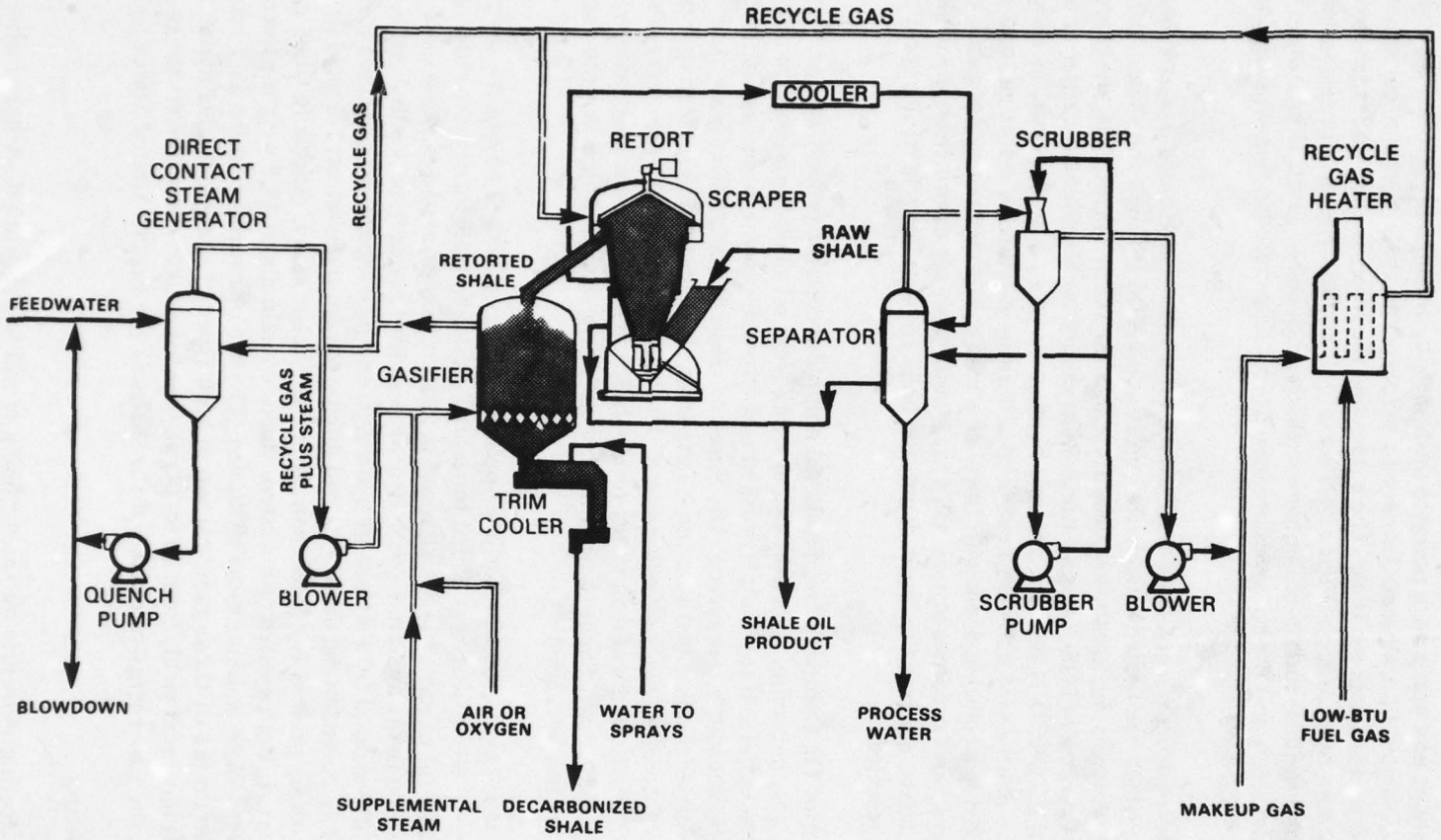
In *solid-heat-carrier retorts,* shale is mixed with hot solids (such as sand, spent shale, or ceramic balls), which are heated outside the retort and cycled through the shale. As in the gas-recycle technologies, no combustion occurs inside the retort. TOSCO II, developed by The Oil Shale Company (TOSCO), and Lurgi-Ruhrgas are both solid-heat-carrier retorting processes. In the TOSCO II process, ceramic balls are used as a heat carrier, as shown in Figure 5-8. The marble-size balls are heated by a burning mixture of retort gas and air to 649°C and mixed in a rotating drum with finely crushed shale preheated by hot gases, where heat is transferred and pyrolysis occurs. Oily vapor and gases are drawn from the drum. As the ball/shale mixture leaves the retort drum, the balls are separated from the spent shale, reheated, and recycled.

The Superior Oil Company has developed a unique retorting process designed to produce shale oil, gas, nahcolite, soda ash, and alumina from oil shale containing quantities of nahcolite and dawsonite. If the shale is crushed and screened prior to retorting, 80 to 95 percent of the nahcolite can be recovered. The Superior retort (Figure 5-9) is shaped like a circular tunnel with a traveling bed that moves the shale through loading, retorting, residual carbon recovery, cooling, and unloading zones. The shale is pyrolyzed by hot gases that are heated by spent shale. Steam and air in the residual carbon recovery zone react with retorted shale to form product gas. Spent shale is discharged to the leaching plant for the chemical recovery of soda ash and alumina.

IGT has developed a hydroretorting operation for processing lean eastern shales. As shown in Figure 5-10, hydrogen is added to retorting shale to transform more residual carbon into product oil or gas. The retort vessel is divided into three zones. Raw shale is fed into the top of the retort and mixed with hydrogen at high pressure in the first zone. Then the shale is hydroretorted by a stream of hydrogen, and oily vapors and gases are released. The spent shale is cooled in the third zone and discharged from the retort. Oil yield from the IGT hydroretorting process is higher than from the Fischer assay, especially when eastern shales are retorted. Both eastern and western shales contain about 13.5 weight percent carbon, but western shale contains more hydrogen. The use of hydrogen in the IGT retorting process converts more of the organic carbon in both types of shale to usable hydrocarbon products. This increased yield, from 10 to 25 gal./ton for eastern shales, offers the prospect of recovering the vast energy resources of the shales in the eastern United States.

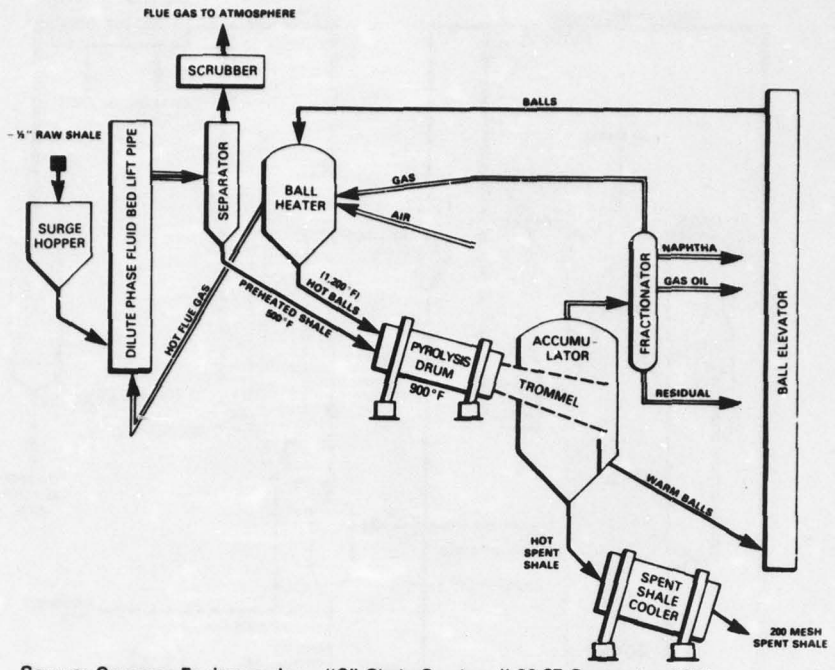
In-Situ Retorting

In-situ retorting pyrolyzes oil shale while it is still in the ground. A heat carrier is introduced into the shale bed through an injection well to pyrolyze the kerogen in the shale. The



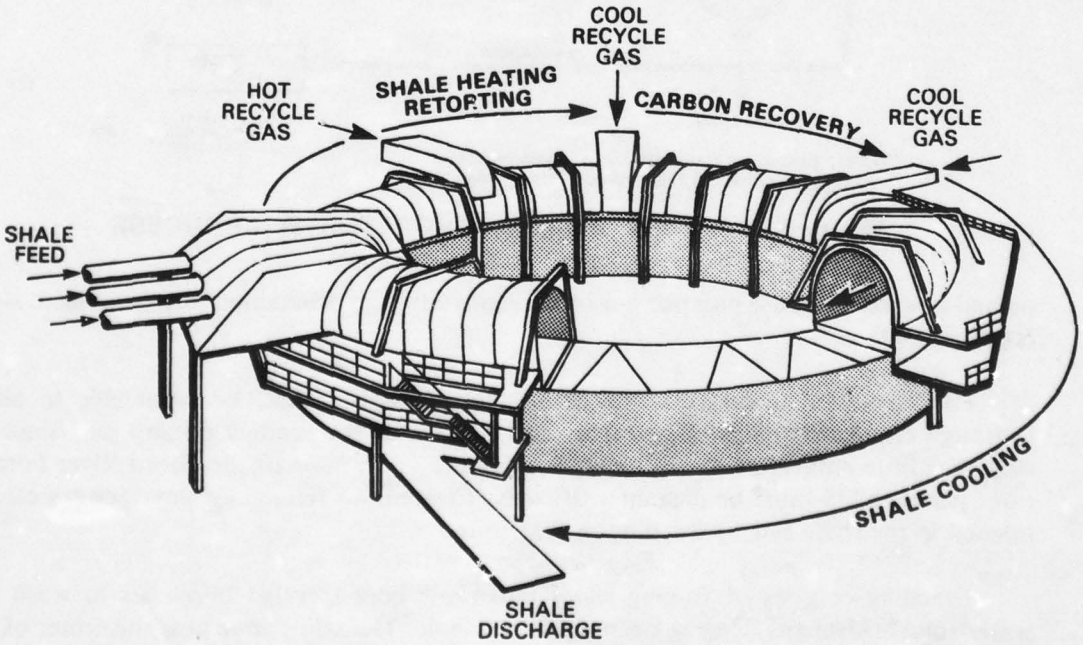
Source: Colorado School of Mines Research Institute, "A Practical Approach to Development of a Shale Oil Industry in the United States," October 1975.

Figure 5-7. UNION STEAM-GAS RECIRCULATION RETORTING PROCESS



Source: Cameron Engineers, Inc., "Oil Shale Seminar," 26-27 September 1977.

Figure 5-8. TOSCO II PROCESS



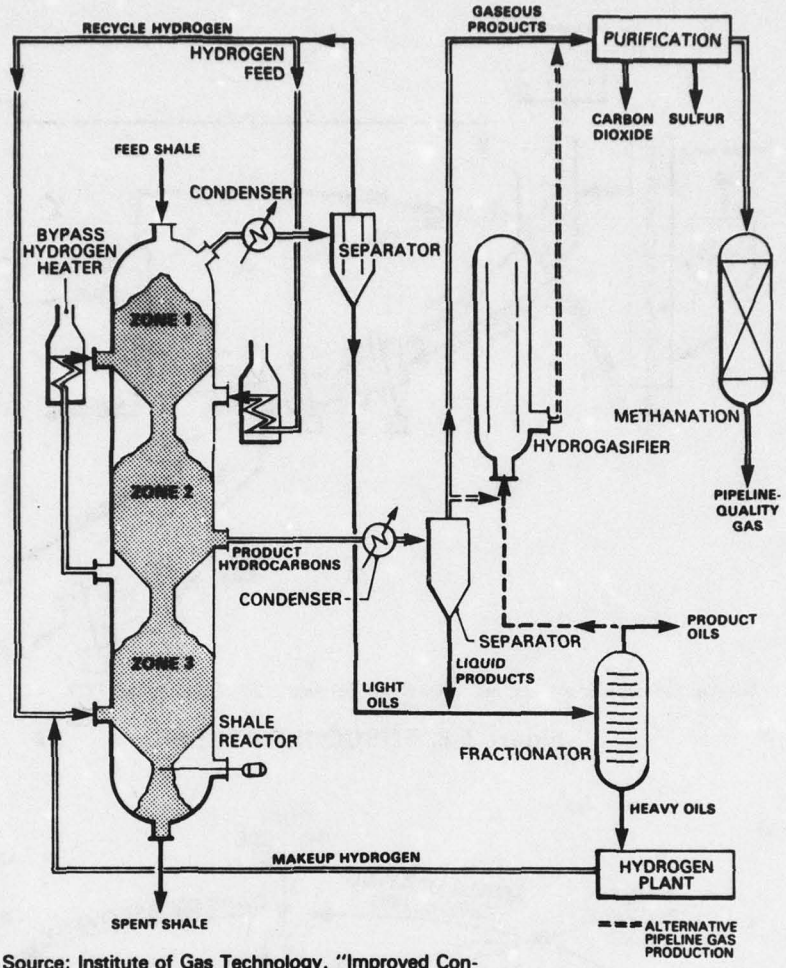
Source: J. H. Knight, "Superior's Circular Grate Oil Shale Retorting Process," presented to the International Symposium on Oil Shale Chemistry and Technology, Jerusalem, Israel, October 1978.

Figure 5-9. SUPERIOR CIRCULAR GRATE RETORT

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Source: Institute of Gas Technology, "Improved Conversion of Oil Shale to Hydrocarbon Fuels," May 1974.

Figure 5-10. IGT OIL SHALE HYDRORETORTING PROCESS

oil and gas produced are pumped out of the retort through production wells; the spent shale remains in place.

For successful underground retorting, the shale bed must be permeable to allow thorough circulation of the heat carrier and passage of the product oil and gas. Since oil shale has little natural permeability, except for the saline zone of the Green River Formation, permeability must be created artificially. Continuous fissures or passageways can be opened in the shale bed by leaching or fracturing.

Leaching consists of forcing water into shale beds through boreholes to wash out water-soluble elements, leaving openings in the shale. The saline zone near the center of the Piceance Basin contains soluble nahcolite, some of which has been leached naturally by groundwater. Additional leaching by water injection creates a porous shale bed.

One of the more common fracturing techniques is hydrofracturing. Water is injected into a shale bed under high pressure until the water pressure equals the overburden pressure and causes the shale to crack. The fractures are filled with a mixture of sand and water; the sand keeps the fractures open when the water is removed. Explosive fracturing, alone or combined with hydrofracturing, uses desensitized nitroglycerin, liquid explosives, or explosive slurries to crack the shale formation. Other fracturing techniques include electrofracturing, ultrasonic destruction, and use of nuclear explosives, high-pressure foam or steam, or lasers.

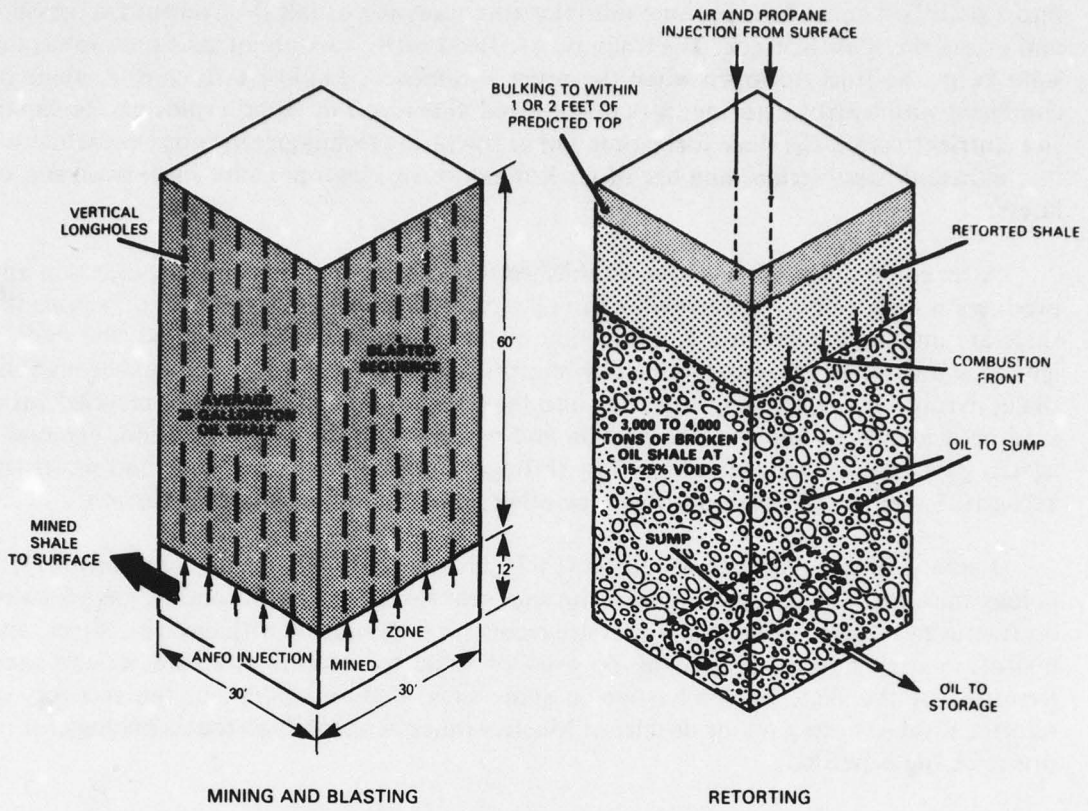
After communication has been established through the shale between the injection and production wells, subsurface retorting can take place. The two basic methods of heating the shale are internal combustion and injection of hot gases. In the first method, the shale is ignited and combustion is maintained by injecting air. The combustion spreads through the shale, pyrolyzing the kerogen. Injection into the retort of air and propane or recycled gas is used occasionally to improve combustion and pyrolysis. In the second method, externally heated gases are introduced, which flow through the fractures in the shale and retort the kerogen. Superheated steam, nitrogen, or other gases can be used as heat carriers.

Laramie Energy Technology Center (LETC) has been developing in-situ retorting technology since 1966. Field tests at nine in-situ sites near Rock Springs, Wyoming, have focused on fracturing, retort ignition, and product recovery. Experiments with electro-, nitro-, and hydrofracturing have increased the porosity of shale formations at several of the sites. Retorting of the shale by combustion at some sites produced shale oil, but recovery of retorted products was a major problem.[6] Much additional research on the technology for in-situ retorting is needed.

The difficulty of creating a permeable shale bed has prompted the development of modified, or mine-assisted, in-situ retorting. In vertical modified in-situ retorting, 10 to 30 percent of the shale is removed from the bottom of the deposit and the remaining shale is fractured to create a chimney of shale rubble. The shale is retorted in this chimney from top to bottom. In horizontal modified in-situ retorting, the overburden is lifted, in some cases, and the shale seam is fractured to retort the shale from side to side. Combined mining and fracturing provide greater permeability and therefore aid in the flow of heat carriers and crude shale oil through the formation.

Occidental Oil Company has been testing vertical modified in-situ retorting (Figure 5-11) since 1972 on shales at Logan Wash in the Piceance Creek Basin. Construction of the retort is begun by mining part of the shale bed to create the total void volume desired for the retort. Explosives then are used to collapse the roof of the mine and distribute the void volume throughout the designated retort area of the shale deposit. The mine entrance is sealed, heat is introduced, and the shale rubble is retorted. Shale oil collects in a sump, or pit, at the bottom of the retort and is pumped to the surface. Occidental has tested six modified in-situ retorts of various sizes and designs, solved many technical problems, and produced more than 34,000 bbl of shale oil. Occidental considers its modified in-situ retorting process commercially feasible.[6,7]

Geokinetics, Inc., is developing horizontal modified in-situ retorting technology, as



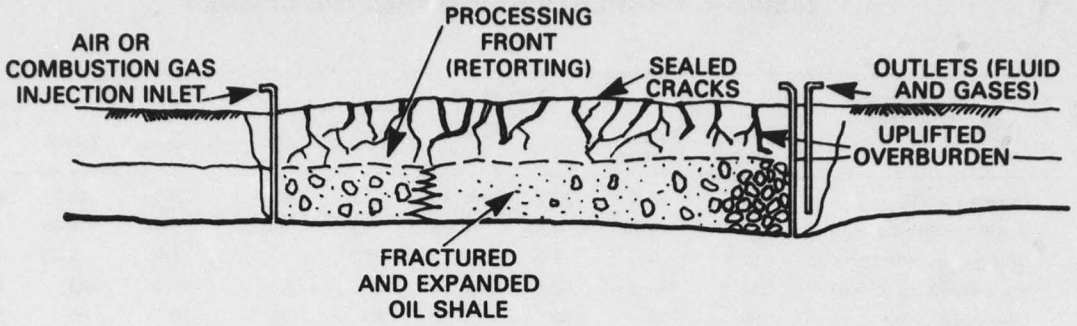
Source: Cameron Engineers, Inc., "Oil Shale Seminar," 26-27 September 1977.

Figure 5-11. OCCIDENTAL MODIFIED IN-SITU SHALE OIL RECOVERY PROCESS

shown in Figure 5-12, on the shallow, thin shale beds in Uinta County, Utah, for which this technology is particularly suited. Permeability of the shale deposit is increased by detonating explosives to raise the overburden and fracture the shale. The shale is ignited with burning charcoal, and combustion is sustained by the injection of air or gas as the retorting zone moves from side to side through the shale deposit. Geokinetics is currently at work on 16 horizontal in-situ retorts, including preparation of the four largest yet attempted. Two of the largest beds will be about $149 \times 55 \times 9$ m thick.

Surface Versus In-Situ Retorting

The technology for surface retorting is more advanced and more clearly delineated than it is for in-situ retorting. Process variables are easier to monitor and control in aboveground



Source: U.S. Department of Energy, "Fossil Energy Research and Development Program of the U.S. Department of Energy, FY 1979," DOE/ET-0013(78), March 1978.

Figure 5-12. GEOKINETICS MODIFIED HORIZONTAL IN-SITU PROCESS

retorts than in underground retorts. However, surface retorting requires large-scale commercial plants; large-scale oil shale mining, hauling, and crushing operations; and large-scale disposal of spent shale. Also, it is limited to minable shale, which is estimated to include only one-third of the 1.8 trillion bbl of shale oil contained in the Green River Formation.[4]

In-situ retorting is applicable to a greater variety of shale beds—deep, shallow and thin—than are mining and surface retorting, and minimizes or eliminates requirements for mining, handling, crushing, transportation, and spent-shale disposal. However, fracturing oil shale for in-situ retorting requires intensive energy, and fracturing techniques need further refinement. Modified in-situ retorting presents somewhat of a compromise, necessitating some mining and handling but offering more process control.

Increasing production from demonstration to commercial scale presents uncertainties for all retorting technologies; the first U.S. commercial plants are likely to combine various surface processes, thereby improving resource utilization. Use of an internal-combustion or gas-recycle retort to process coarse shale and a solid-heat-transfer retort to process fine shale minimizes the resource loss inherent in using a single retort design. Similarly, use of a surface retort in conjunction with a modified in-situ retort provides greater resource utilization.

Shale Oil Characteristics

Generally, crude shale oils are heavy, viscous liquids with high pour points, high nitrogen content, and moderate sulfur content.[7] Table 5-4 presents the properties of various shale oil crudes and indicates the difference between shale crudes and Saudi light, the benchmark crude for the petroleum industry.

Transportation and Storage

Below 21 to 32 °C, most crude shale oil is too viscous to transport by pipeline and apt to solidify over extended periods, making it impractical to store or transport by rail car or tank truck. Before being transported from retorting sites to refineries, the shale oil can be treated,

Table 5-4. PROPERTIES OF SHALE OIL CRUDES

Properties	U.S. Surface						U.S. In Situ		Saudi Light[d]
	Paraho[a] Direct	Paraho[b] Indirect	Union A[c]	Union SGR[b]	TOSCO II[c]	IGT[b]	Occidental[a]	LETC[a]	
Gravity (°API)	19.3	20.6	20.7	35.2	21.2	31.9	25.0	19.5	33.4
Sulfur (weight percent)	0.71	0.71	0.81	0.06	0.9	0.93	0.64	0.60	1.8
Nitrogen (weight percent)	2.0	–	1.9	–	1.9	–	1.3	2.16	–
Viscosity (SUS at 100°F)	364	190.3	92.6	48	106	37	80.1	543	45.6
Pour point (°F)	85	75	90	75	80	30	50	80	–30
50 percent distillation point	806	–	688	624	700	446	671	–	–

[a]Exxon Research and Engineering Company, "Evaluation of Methods to Produce Aviation Turbine Fuels from Synthetic Crudes," Part I, March 1975.

[b]U.S. Naval Ship Research and Development Center, "Preliminary Characterization of Four Crude Shale Oils," TM28-75-46, May 1975.

[c]Colorado School of Mines Research Institute, "A Practical Approach to Development of a Shale Oil Industry in the United States," October 1975.

[d]Leo R. Aalund, "Guide to World Crudes—1," *Oil and Gas Journal,* March 1976.

Note: Data on Superior not available.

or upgraded, to reduce its pour point and nitrogen and sulfur concentrations. Other methods to allow transport of crude shale oil are to heat the pipelines to keep the temperature of the oil above the pour point, or to mix the oil with pour point depressants or enough low pour point petroleum crude to reduce the pour point of the shale oil. However, pour point depressants can be expensive, mixing shale and petroleum crudes requires that the oils be refined together, and heating pipelines or storage facilities is extremely inefficient. The most likely technique, therefore, for preparing crude shale oil for transportation and storage is partial processing or upgrading.[7]

Upgrading

Crude shale oil can be partially upgraded by reducing high pour points and viscosities, thus relieving transportation difficulties, or it can be more thoroughly upgraded by also reducing high nitrogen, oxygen, and sulfur levels to produce a high-quality, semirefined synthetic crude oil that is a premium refinery feedstock. This feedstock can then be refined into liquid fuels by conventional petroleum refining technology (see Chapter 2).

The two basic methods for upgrading shale oil are thermal and hydrotreatment. The first consists of a mild thermal treatment called visbreaking), a severe thermal treatment (coking), or both. Hydrotreating involves hydrogenating the oil in the presence of a catalyst, and generally results in a higher quality synthetic crude oil than does thermal processing. Hydrotreating is more expensive, however. Combining hydrotreatment and thermal methods is probably the most economical way to upgrade shale oil to premium refinery feedstock.[6,7]

ENVIRONMENTAL ISSUES

Extensive studies conducted by the federal government, industry, and public action

groups have identified potential environmental concerns associated with oil shale development. According to the Environmental Protection Agency (EPA), polluting the air with gaseous and particulate emissions from blasting, mining, crushing, transporting, and retorting shale; using large quantities of water for process cooling and revegetation—supplies of which may not be adequate for both local residents and an oil shale industry; possibly contaminating water; and disrupting land by mining shale, disposing of spent shale, and building roads, plants, and towns are among the issues of concern.[8] An overview of environmental issues associated with oil shale production is provided in Table 5-5.

Table 5-5. POTENTIAL ENVIRONMENTAL CONCERNS

Phase	Oil Shale Processes	Physical Disturbances	Pollutant Discharges	Affected Resources	
				Physical	Socioeconomic
Extraction through Retorting	Surface	Aquifer local interruption Land disconfiguration (stripmining) Roof collapse Noise (drilling, retorting) Retorted shale waste piles	Runoff or leachate (metals, organics, salts) from retorted shale pile Dust from mining, crushing, and grinding Fugitive emissions and offgases from retort (venting to air) Contaminated retort water (metals, organics, salts) in settling ponds	Water for dust control, process cooling and vegetation and community use Secondary recovery of minerals	Financing Labor force Community services Housing Power Equipment
	True In-Situ	Work site disturbance Subsidence or uplift Noise (drilling, fracturing) Aquifer local interruption Heat	Leachate (metals, organics, salts) from retorted shale into aquifer Fugitive emissions and offgases from retorting (venting to air) Contaminated retort water (metals, organics, salts) in containment ponds	Water for community use and process cooling	
	Modified In-Situ	Aquifer local interruption Subsidence or uplift Noise (drilling, fracturing) Raw shale waste piles Heat	Leachate (metals, organics, salts) from retorted shale into aquifer Runoff or leachate (mainly salts) from raw shale piles Dust from mining or fracturing Fugitive emissions and offgases from retorting (venting) Contaminated retort water (metals, organics, salts) in settling ponds	Water for community use, processing, and vegetation of raw shale	
Upgrade through End-Use	All Processes	Land disturbances for facilities, roads, or other transportation Physical plants	Evaporation and emissions of crude oil volatiles during storage, upgrading, and refining Accidental spillage	Water for upgrade or end-use stages and community use	

Source: U.S. Energy Research and Development Administration, "Oil Shale—FY 1977," Environmental Development Plan F-01(77), June 1977.

Many environmental problems associated with a shale oil industry can be controlled. Water and wetting agents on conveyors and transportation units, baghouse filters in crushing units, and wet scrubbers in retorts will minimize dust and particulate emissions. Toxic gases will be treated, and contaminated water can be cleaned or recycled for industrial use. Spent shale will be returned to the mines or stored on the surface and revegetated.

Industry and governmental agencies are seeking solutions to environmental problems associated with the development of oil shale. Environmental activities are an essential element of field work undertaken by DOE, either in-house or through industry contracts. DOE's oil shale environmental development plan sets out environmental, health, safety, and socioeconomic issues relevant to oil shale development, and an action plan to assess and alleviate environmental impacts.[9]

RESEARCH AND DEVELOPMENT

In the United States, development of an oil shale industry has progressed and regressed relative to the availability of petroleum. During three separate periods, shale oil production has been on the verge of expanding into a national industry. Shale oil was produced commercially in the 1850s, but the discovery of petroleum in Pennsylvania in 1859 quickly removed the need for shale oil. In the 1920s, 30,000 mining claims were filed and 200 companies were formed to produce shale oil to replace dwindling supplies of domestic oil, but the discovery of large oil fields in eastern Texas preempted the development of an industry.[10] Insufficient supplies of oil during World War II prompted the Synthetic Liquid Fuels Act of 1944, which chartered BOM to develop fuels from domestic shale deposits. Since 1944, pilot plants have operated intermittently in the western U.S. shale deposits, but intensive work on oil shale was deferred again by the discovery of oil in the Middle East. The current revival of interest in oil shale as a source of liquid fuels is again the result of projected petroleum shortages.

Federal energy authorities considered first-generation surface retorting ready for trial in a 10,000 bbl/day demonstration retort in 1975, given a favorable economic situation, and shifted emphasis in the federal oil shale R&D program to the development of various in-situ technologies. Major U.S. oil shale projects, including some private efforts, are listed in Table 5-6. Process support and field studies are being conducted on fracturing techniques, oil recovery from fractured shale, and shale oil refining. LETC, as the "project manager" of the federal effort, is conducting and monitoring in-house field tests at Rock Springs, Wyoming, studying environmental issues (restoring and revegetating spent shale, for example), and evaluating shale oils and in-situ and modified in-situ retorting of oil shales. R&D on oil shale being conducted by national laboratories includes studies of water requirements for in-situ retorting by the Lawrence Berkeley Laboratory, modified in-situ oil shale retorting technology projects by the Lawrence Livermore Laboratory, explosive fracturing studies by the Los Alamos Scientific Laboratory, and in-situ bed preparation and advanced instrumentation and rock mechanics support by the Sandia Laboratories.

The Navy's R&D efforts include producing, refining, and testing synthetic fuels derived from shale oil. Although there were some physical and chemical deficiencies, the synthetic fuels met a majority of standard specification requirements. Tests demonstrated the feasibility of using shale oil to produce military specification fuels.[11,12]

The Navy also is directing a joint DOD/DOE oil shale program to obtain an optimal yield of military specification fuels. By September 1978, 88,225 bbl of shale oil had been produced from the Naval Oil Shale Reserves. The Navy contracted with Standard Oil of Ohio (Sohio) to refine this shale oil into military specification fuels in late 1978 at Sohio's refinery in Toledo, Ohio. The refined fuels are scheduled for distribution to various Army, Navy, Air Force, DOE and National Aeronautics and Space Administration laboratories in 1979 for testing and evaluation. DOE's role in this project is to develop and extend technology for producing synthetic fuels, as well as to demonstrate the potential of the refining technology for commercial use.

Table 5-6. U.S. OIL SHALE PROJECTS

Project	Location	Technology	Production		Status
			Capacity Goal (bbl/day)	Projected Date	
Ashland Oil,[a] Occidental Oil	Tract C-b, Piceance Basin	Vertical modified in-situ	57,000	1985-87	Shaft sinking in progress; construction of initial retorts scheduled for 1982.
Colony (TOSCO, Arco)	Parachute Creek	Surface retorting	47,000	Suspended[b]	Construction of commercial modules scheduled for 1980.
Dow Chemical	Michigan Basin, Antrim Shale	True in-situ, modified in-situ	–	1981	Gas recovery feasibility
Equity Oil	Piceance Creek	Solution injection, modified in-situ	–	1981	Steam-injection feasibility; site preparation in progress.
Geokinetics, Inc.	Uinta County	Horizontal modified in-situ	7-13 2,000-5,000	Now producing 1982	Several small retorts successfully burned; work on larger retorts in progress.
Getty Oil	Piceance Basin	Surface thermal extraction	–	–	Getty R&D proposal being considered by DOE
Institute of Gas Technology	Appalachian Basin	Surface hydroretorting	–	–	IGT R&D proposal being considered by DOE
MECCO	Uinta Basin	In-situ	No information available		
Occidental Oil	Logan Wash	Vertical modified in-situ	300 70,000	Produced in 1977 1979	Five retorts burned; sixth retort under way; 11,287 bbl produced.
Paraho (Development Engineering, Inc.)	Anvil Points	Surface retorting	150-200	Produced in 1978	Shut down due to lack of funding; 88,225 bbl produced.
Rio Blanco (Gulf, Amoco)	Tract C-a, Piceance Basin	Vertical modified in-situ, surface retorting	50,000	1987	Modular program consisting of 5 retorts scheduled for completion by 1982.
Superior Oil	Piceance Creek	Multimineral recovery, surface retorting	13,000	Suspended	Company seeking land exchange with federal government.
Talley-Frac	Tipton Member, Green River Basin	True in-situ	5,000	–	Project discontinued, January 1979.
TOSCO-Sand Wash	Uinta Basin	Modified in-situ, surface retorting	75,000	Suspended[b]	Feasibility studies in progress.
Union Oil	Parachute Creek	Surface retorting	7,000	Suspended[b]	Construction of experimental mine and plant dependent on passage of $3/bbl tax credit.
White River (Sohio, Sunoco, Phillips)	Tracts U-a and U-b, Uinta Basin	Modified in-situ, surface retorting	100,000	Suspended	Operations suspended due to legal proceedings on ownership of lands.

[a]Ashland Oil withdrew from this project on 14 February 1979.

[b]Operations were suspended due to economic uncertainties.

Source: Communication with Office of Shale Resource Applications, U.S. Department of Energy, and with industry representatives; U.S. Department of Energy, "Commercialization Strategy Report for Oil Shale," Draft, November 1978; and Lawrence Berkeley Laboratory, "Oil Shale Environmental Issues and Controls," December 1978.

EPA funds research on oil shale through two basic programs. The purpose of the Process and Effects Program is to characterize the expected types and magnitudes of pollutants, define toxic characteristics, trace pollution of the environment, determine the effects on local ecologies, and assess the total impact of oil shale development on the environment. In its Control Technology Program, EPA is investigating mining techniques; studying reclamation of mined lands and revegetation of spent shale; assessing pollution controls for air, water, and solid wastes; and measuring effluents from retorting operations.[8]

COMMERCIALIZATION

According to a draft DOE report assessing the commercial readiness of oil shale, the U.S. oil shale resource is sufficient to support a stable industry, and technology is adequate for initiating commercial operations given the resolution of economic, environmental, and institutional difficulties. Environmental concerns probably will determine the size of a shale oil industry, and environmental and regulatory requirements could determine the rate of industrialization. Commercial development is very sensitive to industry's perception of government policy, and an active federal role is necessary to remove the barriers to oil shale development. In the report, a two-pronged strategy for creating an environment favorable to the commercialization of oil shale is recommended. The strategy calls for a broad program of flexible incentives to ensure a fair return on industry's initial commercial investments, and a comprehensive government policy that results in consistent federal management of matters relating to oil shale. Shale oil production goals are 150,000 bbl/day by 1985, 600,000 bbl/day by 1990, and 1.4 million bbl/day by 2000.[13]

The move to commercialize shale oil soon has been supported by several recent actions. For example, an entitlement benefit was extended to oil shale refiners, effective July 1978. Refiners that use domestically produced derivatives of oil shale can currently get about $2/bbl from the entitlements program.[14] At DOE, oil shale was moved from Energy Technology, responsible for research and development, to Resource Applications, responsible for commercialization strategy. DOE will try to get a $3/bbl tax credit approved by Congress in early 1979.[15] Union Oil Company states that work can begin on a 9,000-bbl/day surface retorting module as soon as such a tax credit is available.[16]

The uncertain economics of commercial oil shale operations are reflected in the broad cost estimates shown in Table 5-7. Shale oil produced by vertical modified in-situ retorting, at an estimated cost of $13.50/bbl, is competitive with imported crude oil, at a world price of $15.66/bbl. The cost of shale oil produced in a surface retort is estimated to be $16.25/bbl. Assuming the world price of imported crude oil is $19.95/bbl by 1985 and the cost of shale oil does not change, shale oil from both retorting processes will be competitive with imported crude by 1985.[13]

Table 5-7. SHALE OIL COST/BARREL

Technology	Investment Cost[a]	Operating Cost[b]	Production Cost[b]
Surface retorting	$20,000-25,000	$ 7-15	$20-30
Vertical modified in-situ	12,000-20,000	8-13	15-25
Horizontal in-situ	2,000-4,000	18-28	19-30
Multimineral	18,000-25,000	8-15	16-30

[a]Based on daily plant capacity (in barrels).

[b]Includes upgrading costs at existing refineries to produce a refinery feedstock.

Source: U.S. Department of Energy, "Commercialization Strategy Report for Shale Oil," Draft, 1978.

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Research Laboratory Workshop on Basic Research Needs for Synthetic Hydrocarbon Jet Aircraft Fuels, 15-16 June 1978.

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14. U.S. Department of Energy, *DOE Information,* 12 May 1978.

15. *Inside DOE,* 4 October 1978.

16. Telephone conversation with John Hopkins of Union Oil Company, September 1978.

6. TAR SANDS

Tar sands, oil sands, oil-impregnated rocks, bitumen-bearing rocks, and bituminous sands are interchangeable terms for consolidated or unconsolidated rocks—usually sandstone, limestone, or siltstone—containing a hydrocarbon material known as bitumen. Bitumen, a very viscous to solid form of crude petroleum that is not recoverable economically through a well, can be extracted from tar sands and treated, or upgraded, to a liquid "synthetic" crude oil.

The terms heavy oil and tar sands are often used synonymously; there is no definitive line separating a conventional oil field with a very viscous crude oil from a tar sands deposit with a slightly more viscous crude bitumen.[1] Neither can be produced in commercial quantities by primary petroleum recovery techniques. The bitumen in tar sands ranges in gravity from less than 10 to 15°API and heavy oil ranges from 15 to 20°API.[2] Because of the overlap, classifying and quantifying tar sands and heavy oil resources are difficult.

Historically, tar sands have been mined for asphalt to pave roads. Currently, tar sands also are considered a source of crude petroleum. Synthetic crude oil obtained from extracting and upgrading bitumen can be used much like conventional crude oil—it can be refined into gasoline, jet fuels, and other petroleum products. In particular, research sponsored by the U.S. Navy has indicated that quality JP-5, an aviation fuel, can be obtained from tar sands oil.[3]

RESOURCES

World resources of tar sands bitumens and heavy oils ranging in gravity from 6 to 20°API recently have been estimated conservatively at about 2.2 trillion bbl of oil in place.[4,5] The resource base is aggregated into 16 very large deposits concentrated in the northern hemisphere. The major deposits are listed in Table 6-1.

At least 2 trillion bbl of these tar sands/heavy oil resources are in eastern Venezuela and western Canada. The Orinoco tar sands/heavy oil belt of eastern Venezuela is about 600 km long and 60 km wide (see Figure 6-1). Although several hundred wells and thousands of kilometers of seismic lines have been used to estimate the energy potential of these deposits, current resource estimates vary widely, from about 1 trillion to 4 trillion bbl of oil in place.[4,6] The heavy, sour, metal-laden oil ranges in gravity from 8 to 14°API, has more than 4 percent sulfur content and high levels of vanadium and nickel, and is covered by overburden ranging in thickness from a few hundred to a few thousand feet.[6,7] Only 15 percent of the resource is considered recoverable using current technology. Commercial development of the Orinoco oil belt is to begin when 20 percent of the resource is technically recoverable.[6]

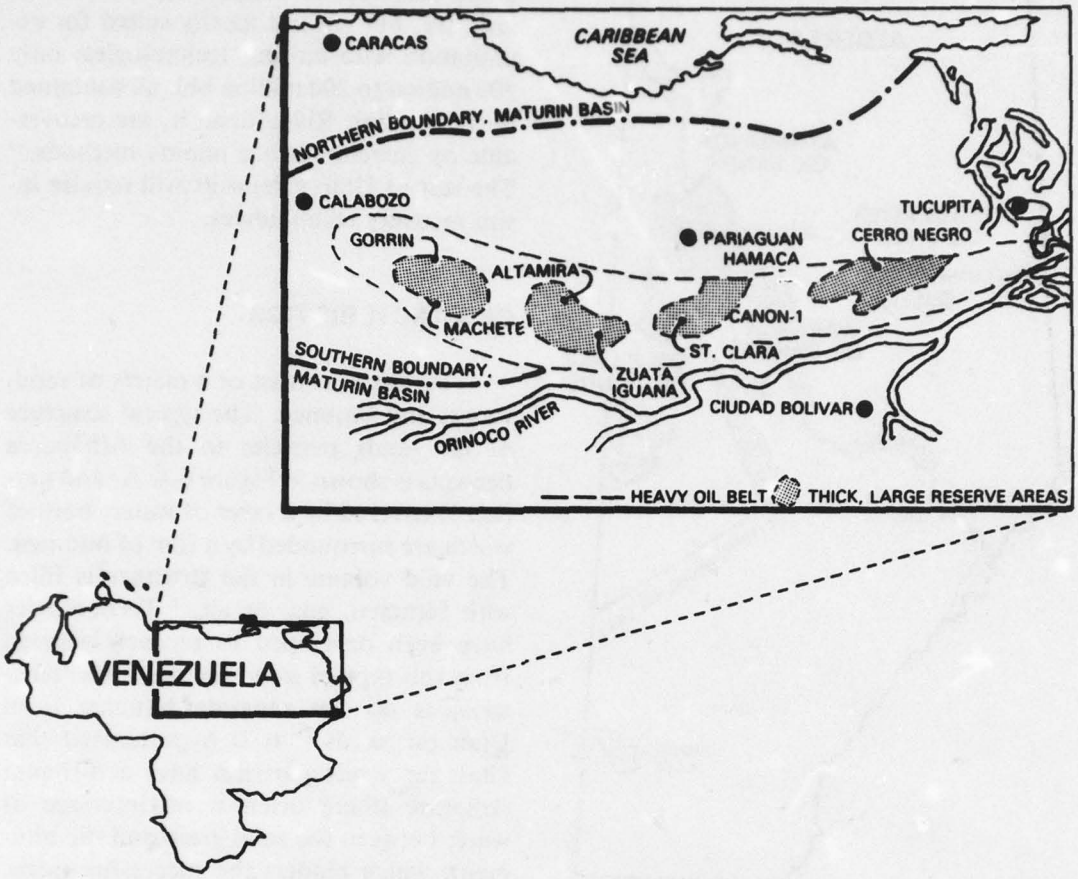
Table 6-1. MAJOR WORLD TAR SANDS/ HEAVY OIL DEPOSITS

Location	Volume in Place (Billion bbl)	Age and Type of Reservoir
Venezuela		
Orinoco heavy oil belt	1,050	Oligocene and early cretaceous sands
Western Canada		
Athabasca	720	Early cretaceous sands
Cold Lake	159	Early cretaceous sands
Wabasca	37	Early cretaceous sands
Peace River	64	Early cretaceous sands
Canadian Arctic		
Melville Island	<1	Triassic sands
USSR		
Melekess	123	Permian sands and dolomites
Siligir	13	Cambrian carbonates
Olenek	8	Permian sands
United States		
Tar Triangle	16	Permian sands
Circle Cliffs	1	Permian sands
Sunnyside	4	Eocene sands
P.R. Springs	4	Eocene sands
Hill Creek	1	Eocene sands
Asphalt Ridge	1	Eocene sands
Malagasy		
Bemolanga	2	Liassic sands
Total	2,203	

Sources: G. J. Demaison, "Tar Sands and Supergiant Oil Fields," *Association of American Petroleum Geologists' Bulletin,* Vol. 61, No. 11, November 1977; and Energy Resources Conservation Board, *Alberta's Reserves of Crude Oil, Gas, Natural Gas Liquids, and Sulphur,* 17th Edition (Alberta, Canada: December 1977).

The oil sands of Alberta, Canada, extend over 49,210 km^2 and are grouped into four major deposits (see Figure 6-2 and Table 6-2). Data collected from about 5,000 drillholes in Alberta support estimates of 980 billion bbl of crude bitumen in place, which may yield ultimately recoverable reserves of 330 billion bbl of crude bitumen and 250 billion bbl of synthetic crude oil.[5] The Athabasca oil sands deposit alone contains about 627 billion bbl of crude bitumen and is at least four times as large as the giant oil field at Ghawar, Saudi Arabia.[4] Seventy-four billion bbl of in-place reserves in the Athabasca deposit are covered by 0 to 45 m of overburden and are recoverable by current surface mining techniques; 30.4 billion bbl of this is considered a proved recoverable reserve which may yield 22.6 billion bbl of synthetic crude oil. Parts of these Alberta oil sands are being produced commercially, but most are under an overburden of 45 to 760 m of muskeg, glacial till, bedrock, and lean oil sand, and are recoverable only by in-situ technologies still being developed.[8]

In the United States, there are 546 reported occurrences of tar sands in 22 states, yet the total tar sands resource has not been defined.[9] Of these 546 occurrences, 39 concentrated deposits, over 1 million bbl each, are itemized in Table 6-3. These known deposits, located in California, Kentucky, New Mexico, Texas, and Utah, are estimated to contain up to 30 billion bbl of oil in place.[10] The resource content of the other reported occurrences has not been explored realistically and is negligible or at least questionable. For example, 150 million

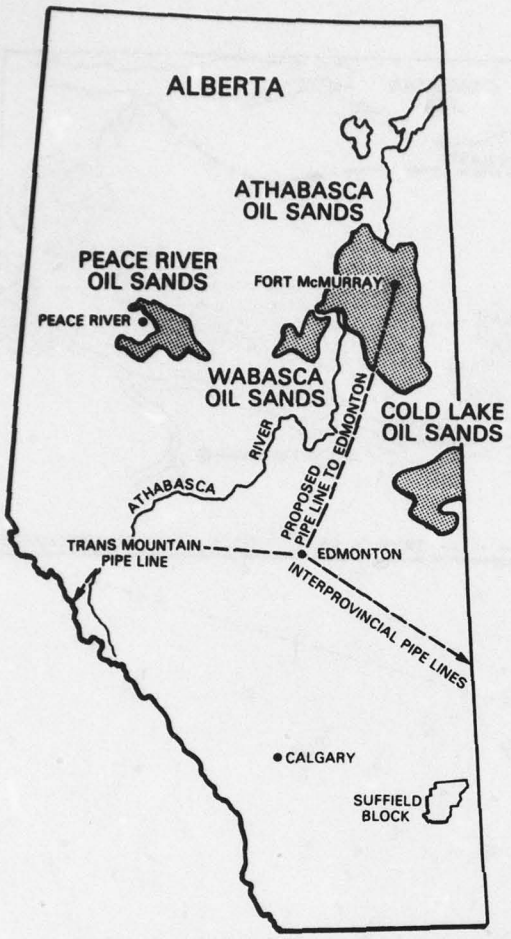


Source: "Large-scale Action Nearer for Orinoco," *Oil and Gas Journal,* Vol. 71, No. 33, 13 August 1973.

Figure 6-1. ORINOCO HEAVY OIL BELT OF VENEZUELA

bbl of oil are estimated to be contained in Alabama tar sands, but the low level of bitumen saturation and the absence of feasibly recoverable concentrations of bitumen prevent them from being classified as a resource.[11] Similarly, oil in place in Kansas tar sands has been estimated at 200 million to 225 million bbl, but a recent evaluation of the deposits revealed that none of the oil is recoverable by present technologies.[12] Until additional work on resource definition is undertaken by more states, estimates of the total U.S. tar sands resource must be considered incomplete.

Currently, 90 to 95 percent of the U.S. resource base is in Utah, which has 23.4 billion to 29.5 billion bbl of oil in place.[2] The major deposits are shown in Figure 6-3. Six deposits in northeastern and central southeastern Utah (Tar Sand Triangle, P.R. Spring, Sunnyside, Circle Cliffs, Asphalt Ridge, and Hill Creek) hold from 1 billion to 16 billion bbl each. Four of these deposits (Asphalt Ridge, Hill Creek, P.R. Spring, and Sunnyside) hold more than 10 billion bbl of low-sulfur oil (less than 0.5 weight percent).[12]



Source: Alberta Federal and Intergovernmental Affairs, *The Alberta Oil Sands Story,* January 1974.

Figure 6-2. LOCATION OF ALBERTA OIL SANDS DEPOSITS

Utah tar sands deposits contain adequate resources to support a tar sands oil industry, but are not ideally suited for exploitation with current technologies; only 100 million to 200 million bbl, all contained in the Asphalt Ridge deposit, are recoverable by current surface mining methods.[13] The rest of Utah's deposits will require in-situ recovery technologies.

CHARACTERISTICS

Tar sands consist of a matrix of sand, water, and bitumen. The typical structure of tar sands particles in the Athabasca deposits is shown in Figure 6-4. A sand particle is covered by a layer of water, both of which are surrounded by a film of bitumen. The void volume in the structure is filled with bitumen, gas, or air.[14] Technologies have been developed to recover bitumen from this type of structure, but these technologies do not separate bitumen from Utah tar sands.[15] It is hypothesized that Utah tar sands particles have a different structure (there often is no interface of water between the sand grain and the bitumen), which hinders the successful operation of Canadian technologies in Utah.[3]

Bitumens extracted from U.S. tar sands generally have higher API gravities, lower sulfur contents, and similar nitrogen levels compared to bitumens extracted from Canadian tar sands.[3,16] Analysis of more than 3,000 cores from Utah's six largest tar sands deposits by the Laramie Energy Technology Center (LETC) characterizes most of these deposits as having good porosity and permeability, with average permeability values suggesting adequate permeability for in-situ recovery. The compressive strength of these sands is characteristic of consolidated rocks. Average bitumen saturation is less than 50 percent of the pore volume.[17] Table 6-4 presents average properties of Utah's major tar sands by deposit.

TECHNOLOGY

Two basic techniques can be used to recover bitumen from tar sands. The first tech-

Table 6-2. ALBERTA OIL SANDS RESERVES OF CRUDE BITUMEN

Deposit and Overburden Depth Interval (m)	Initial in Place (Billion bbl)	Areal Extent (km^2)	Average Pay Thickness (m)	Average Bitumen Saturation (Fraction by weight)	Average Gravity (°API)
Athabasca					
Wabiskaw-McMurray					
0- 14.7	14	324	31	0.101	8
15- 29.7	31	851	31	0.085	
30- 44.7	29	810	28	0.092	
45- 74.7	47	1,094	34	0.092	
75-149.7	95	2,827	32	0.075	
150-299.7	201	9,554	24	0.062	
300-449.7	288	20,461	17	0.058	
450-599.7	12	2,187	8	0.058	
600-749.7	2.5	737	5	0.048	
750+	0.5	215	4	0.048	
Subtotal	720.0	39,058			
Cold Lake					
Upper Grand Rapids					
300-600	42	8,246	6	0.063	14
Lower Grand Rapids					
300-600	67	6,630	12	0.068	12
Clearwater					
300-600	36	3,281	12	0.076	10
McMurray					
300-600	14	2,993	6	0.055	10
Peace River					
Bluesky-Bullhead					
300-449.7	6	927	9	0.054	8
450-599.7	25	2,163	20	0.054	
600-749.7	32	4,253	14	0.050	
750+	1	332	6	0.040	
Subtotal	64	7,675			
Wabasca					
Upper Grand Rapids					
150-299.7	23	2,637	10	0.071	8
300-449.7	1	332	4	0.042	
450+	<0.1	93	2	0.033	
Subtotal	24	3,062			
Middle Grand Rapids					
150-299.7	7.3	1,304	5	0.060	8
300-449.7	0.4	263	3	0.039	
450+	<0.1	49	2	0.042	
Subtotal	7.7	1,616			
Lower Grand Rapids					
150-299.7	5	1,045	7	0.056	8
300-449.7	1.5	547	5	0.044	
Subtotal	6.5	1,592			
Total	980[a]				

[a]Evaluation used 3 weight percent and 1.5 m sand thickness cutoffs.

Source: Energy Resources Conservation Board, *Alberta's Reserves of Crude Oil, Gas, Natural Gas Liquids, and Sulphur,* 17th Edition (Alberta, Canada: December 1977).

nique is to mine the raw material and process it in aboveground facilities. The second method is to recover the bitumen from tar sands in-situ, without removing the sands from the ground.

Table 6-3. U.S. TAR SANDS DEPOSITS WITH RESOURCES OVER 1 MILLION BBL

State and Name of Deposit	Estimated Resources (Million bbl)	
	Low	High
California		
Edna	141.4	166.4
South Casmalia	46.4	–
North Casmalia	40.0	–
Sisquoc	26.0	50.0
Santa Cruz	10.0	–
McKittrick	4.8	9.0
Point Arena	1.2	–
Subtotal	269.8	323.0
Kentucky		
Kyrock area	18.4	–
Davis-Dismal area	7.5	11.3
Bee Spring area	7.6	–
Subtotal	33.5	37.3
New Mexico		
Santa Rosa	57.2	–
Texas		
Uvalde	124.1	140.7
Utah		
Tar Sand Triangle	12,504.0	16,004.0
P.R. Spring	4,000.0	4,500.0
Sunnyside	3,500.0	4,000.0
Circle Cliffs	1,000.0	1,300.0
Asphalt Ridge	1,000.0	1,200.0
Hill Creek	300.0	1,160.0
San Rafael Swell	385.0	470.0
Raven Ridge	125.0	150.0
Argyle Canyon	100.0	125.0
Asphalt Ridge, Northwest	100.0	125.0
Whiterocks	65.0	125.0
Cottonwood-Jacks Canyon	80.0	100.0
Wickiup	60.0	75.0
Minnie Maud Creek	30.0	50.0
Rimrock	30.0	35.0
Willow Creek	20.0	25.0
Pariette	12.0	15.0
White Canyon	12.0	15.0
Littlewater Hills	10.0	12.0
Lake Fork	6.5	10.0
Nine Mile Canyon	5.0	10.0
Chapita Wells	7.5	8.0
Ten Mile Wash	1.5	6.0
Tabiona	1.3	4.6
Thistle	2.2	2.5
Spring Branch	1.5	2.0
Cow Wash	1.0	1.2
Subtotal	23,359.5	29,530.3
Total	23,845.1	30,088.5

Source: L. C. Marchant, C. Q. Cupps, and C. S. Land, "Activity on the Production of Energy From Tar Sands of the U.S.," presented to the International Institute for Applied Systems Analysis, Schloss Laxenburg, Austria, 3-16 July 1976.

Mining

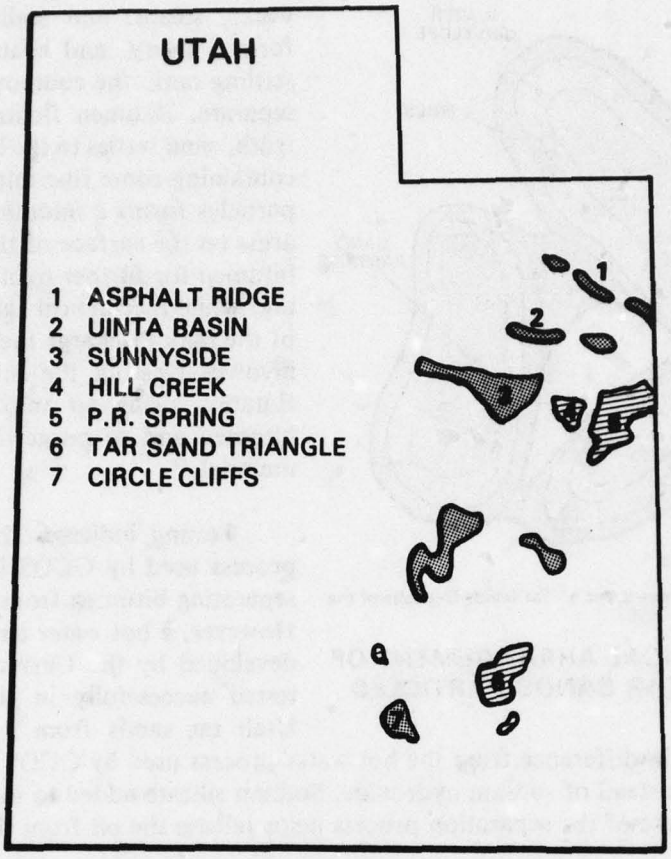
Tar sands can be mined by either surface or underground methods. Because the cost of mining 1 m^3 overburden is about the same as mining 1 m^3 high-grade ore, surface mining generally is used unless the ratio of overburden thickness to ore body thickness exceeds one. Factors such as ore grade, overburden characteristics, and ultimate product market value directly affect this ratio.

Either conventional or extra-large equipment can be used for surface mining. Because of the large scale of mining required to feed even a 45,000 bbl/day tar sands plant (about 100,000 tons of ore/day, excluding overburden removal), commercial operations in Canada are using giant bucketwheel excavators or electric draglines to mine the Athabasca tar sands. One bucketwheel, like the ones being used by Great Canadian Oil Sands, Ltd. (GCOS), can excavate a maximum of 9,000 ton/hour of ore.[14]

Underground methods for mining tar sands are considered less useful, primarily because of the large surface-accessible deposits in Canada, the relatively small size of U.S. deposits, and the prospect of in-situ recovery. The structural makeup of tar sands deposits prohibits conventional hardrock mining, but conventional longwall mining possibly could be modified to recover tar sands. Hydraulic slurry mining techniques are being tested on tar sands. In hydraulic mining, a capsule, containing a high-pressure nozzle, a slurry pump, and piping, is lowered through a casing into a shaft drilled through the tar sands zone into the underlying formation (Figure 6-5). The nozzle directs a stream of water against the tar sands, breaking the material into small pieces, which are entrained in the water as a slurry. The slurry drains into a sump in the underlying zone and is pumped to the surface for processing.

Surface Extraction

A great many processes have been patented in the United States and Canada for re-

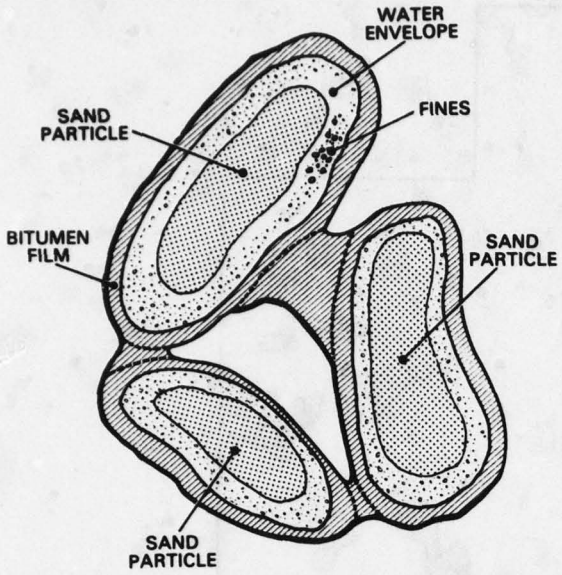


Source: L. C. Marchant, C. S. Land, and C. Q. Cupps, "Activity on the Production of Energy From Tar Sands of the U.S.," presented to the International Institute for Applied Systems Analysis, Schloss Laxenburg, Austria, 3-16 July 1976.

Figure 6-3. MAJOR TAR SANDS DEPOSITS IN UTAH

covering bitumen from tar sands, including hot water processes, solvent extraction processes, combinations of solvents and water, and thermal processes. Basically, the hot water, solvent, and water/solvent separation processes "wash" or dissolve the bitumen out of the tar sands. Thermal processes heat the tar sands until the bitumen is vaporized, drawn off, and condensed into synthetic crude oil.

The hot water separation process, initially developed by Dr. K. A. Clark and currently used in commercial operations by GCOS (see Figure 6-6) and Syncrude Canada Ltd., consists of conditioning, separating, and scavenging. Conditioning the tar sands feed reduces the lumps by ablation (layers of material fall away as they are heated), mixes the feed with



Source: Cameron Engineers, Inc., "Tar Sands Deposits of the United States," May 1976.

Figure 6-4. TYPICAL ARRANGEMENT OF CANADIAN TAR SANDS PARTICLES

water, steam, and sodium hydroxide to form a slurry, and heats the slurry. In a settling tank, the components of the slurry separate. Bitumen floats to the top as a froth, sand settles to the bottom, and water containing some fine mineral and bitumen particles forms a middlings stream. Wiper arms on the surface of the tank collect the bitumen for further treatment and upgrading, while mechanical rakes in the bottom of the tank discharge the sand. Scavenging involves treating the middlings by froth flotation using air to recover additional bitumen and to purge the system of fine material.[14]

Testing indicates that the hot water process used by GCOS is not suitable for separating bitumen from Utah tar sands.[15] However, a hot water technology has been developed by the University of Utah and tested successfully in the laboratory on Utah tar sands from the Asphalt Ridge deposit. The main difference from the hot water process used by GCOS is the addition of sodium silicate instead of sodium hydroxide. Sodium silicate added to the hot water in the conditioning phase of the separation process helps release the oil from the sand.[18]

A hot water/diluent extraction process developed by the U.S. Bureau of Mines represents the general technology of most solvent-assisted water extraction processes (see Figure 6-7). Tar sands feed is conditioned by mixing it with water, a diluent, and an alkaline

Table 6-4. AVERAGE PROPERTIES OF UTAH'S MAJOR TAR SANDS[a]

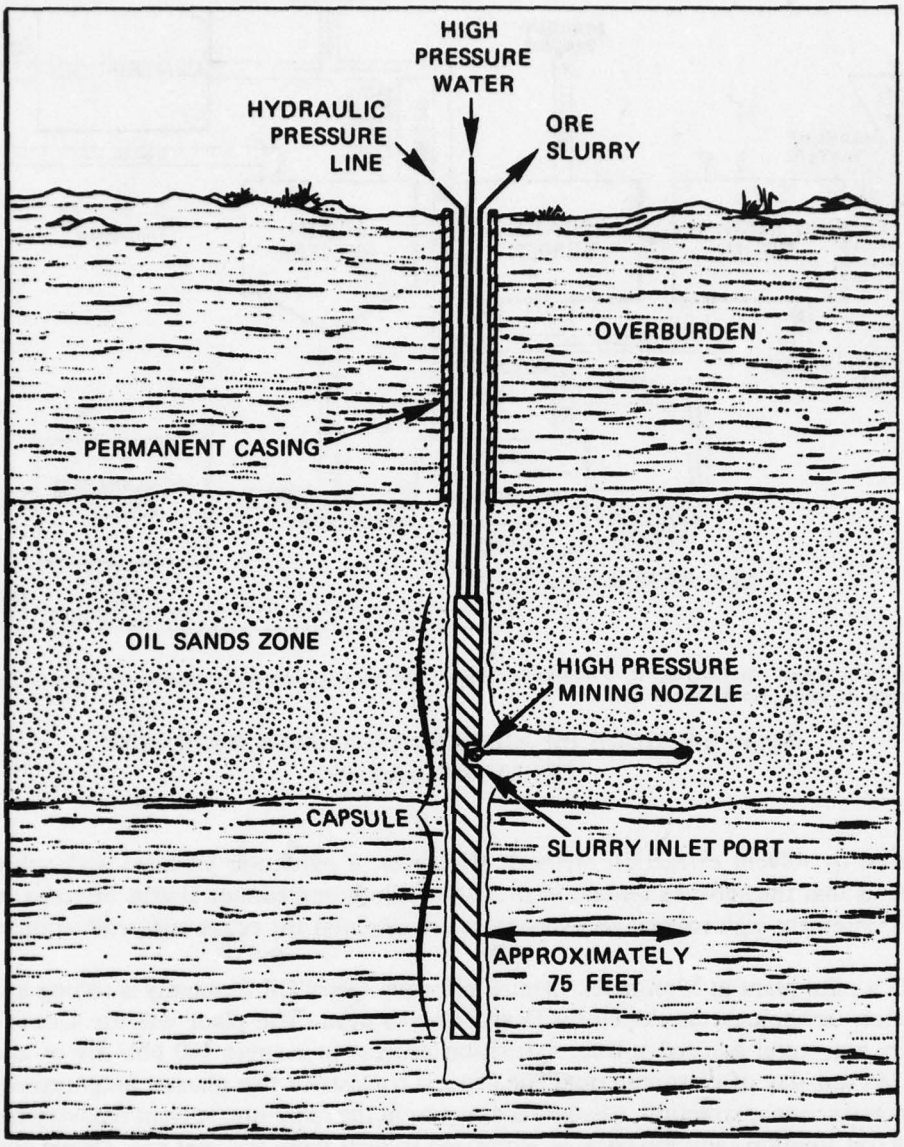
Deposit	Porosity (Percent pore volume)	Permeability (md)	Bitumen Saturation (Percent pore volume)	Water Saturation (Percent pore volume)	Compressive Strength (psi)
Asphalt Ridge	19.6	497	51.4	2.7	2,491
N.W. Asphalt Ridge	22.8	603	45.2	20.2	1,598
Circle Cliffs	12.3	228	17.7	—	—
Hill Creek	20.2	325	29.7	2.1	6,555
P.R. Spring	25.0	1,510	42.5	3.0	4,784
Sunnyside	21.3	729	44.8	—	7,805
Tar Sand Triangle	20.0[b]	207[b]	6.3[b,c]	—	3,242[b]
	19.7	788	70.7	—	—

[a]All values based on samples from cores except as indicated.

[b]Surface samples.

[c]Total liquid saturation (percent by weight).

Source: U.S. Environmental Protection Agency, "Production and Processing of U.S. Tar Sands: An Environmental Assessment," EPA-600/7-76-035, December 1976.

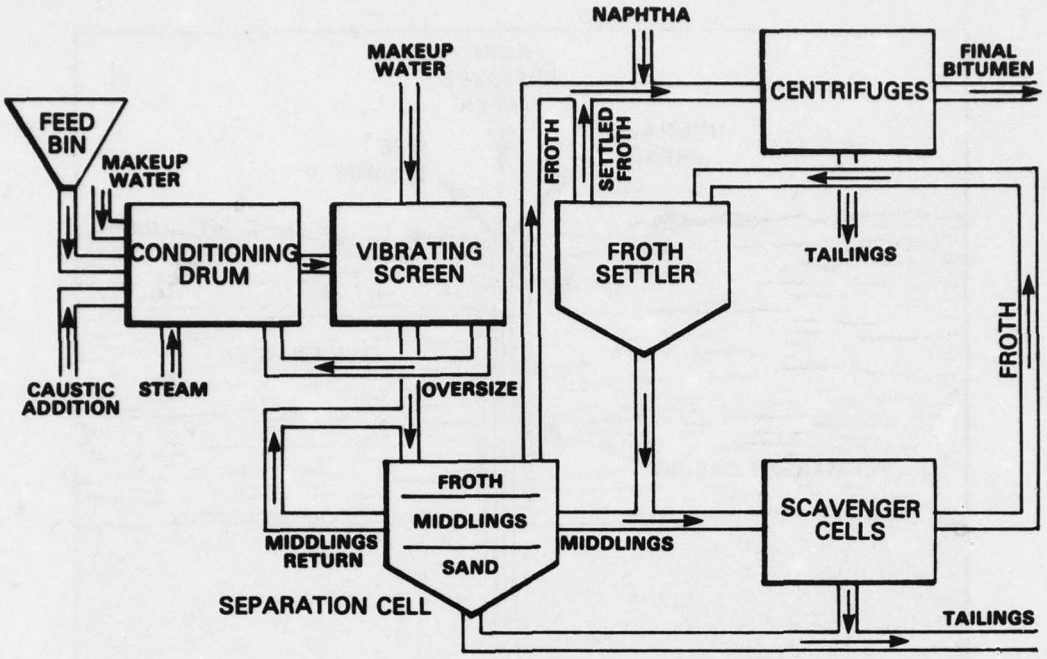


Source: Cameron Engineers, Inc., "Tar Sands Deposits of the United States," May 1976.

Figure 6-5. HYDRAULIC SLURRY MINING TECHNIQUE

agent. The mixture is put in a flotation cell, where a froth of bitumen, diluent, and some water and mineral collects at the top, and sand tailings settle to the bottom. The froth is removed from the top and treated with more diluent. Sand is removed from the bottom and discharged.[15]

Bitumen, which is soluble in light hydrocarbons and organic solvents, also can be



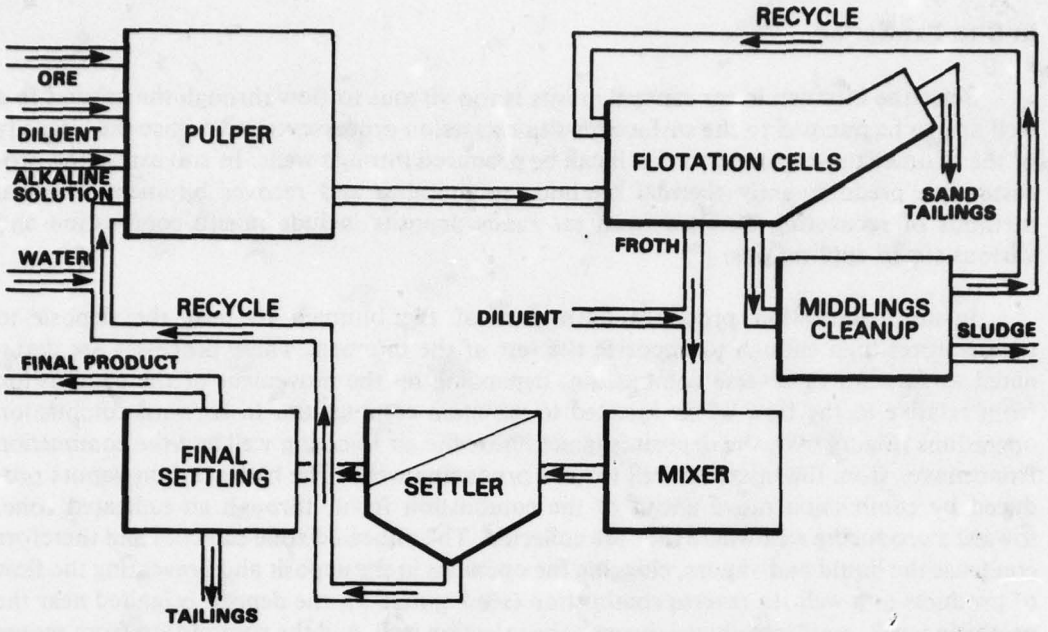
Source: W. L. Oliver, "Oil Recovery from Alberta Oil Sands," 79th National Meeting of American Institute of Chemical Engineers, Houston, Texas, March 1975.

Figure 6-6. GCOS PROCESS FOR BITUMEN RECOVERY FROM TAR SANDS

recovered by solvent extraction methods. However, a particular problem with solvent extraction is that the solvents remain in the sand tailings and cannot always be recovered for reuse. Extremely high solvent recovery rates are essential for economic production.[15]

In a pilot plant at McKittrick field, California, Getty Oil Company is testing a solvent extraction technology developed by Dravo Corporation. The plant will use Dravo's proprietary non-water-assisted solvent extraction process to recover 160 bbl/day of crude oil from 240 ton/day of diatomite ore. The process consists of five phases: preparation of the ore for extraction, extraction, solvent recovery from the spent ore, solvent recovery from the solvent/oil solution, and recovery of vaporized solvent from the vent gas. Dravo considers the solvent recovery adequate to make the process economic.[19]

Guardian Chemical Corporation has developed an extraction technology that uses "Dikor" (proprietary) dissolved in warm water to repel the oil film away from the sand. Tar sands, warm water (about 35°C), Dikor, and breaker bars or balls are mixed in a rotating drum for about 20 minutes. A small amount of water forms a layer of wetness between the film of bitumen and the sand grains. Treating the tar sands with the aqueous solution separates the materials into three distinct layers. The bituminous material floating on top is poured off with some solution, and the bitumen is separated out and shipped to a refinery. The solution of water and Dikor is recycled. The sand is washed and discharged; the wash



Source: Robert M. Lowe, "The Asphalt Ridge Tar-Sand Deposits," *Oil Shale and Tar Sands*, AIChE Symposium Series, Vol. 72, No. 156, 1976.

Figure 6-7. U.S. BUREAU OF MINES HOT WATER-SOLVENT OIL RECOVERY PROCESS

water is reused in the aqueous solution. Most of the Dikor is recovered for reuse. Dikor is said to be nontoxic to plants and animals and to present no environmental hazards for spent sand disposal.[20] A 100 ton/day pilot plant has been constructed and will be tested on the Athabasca deposit.

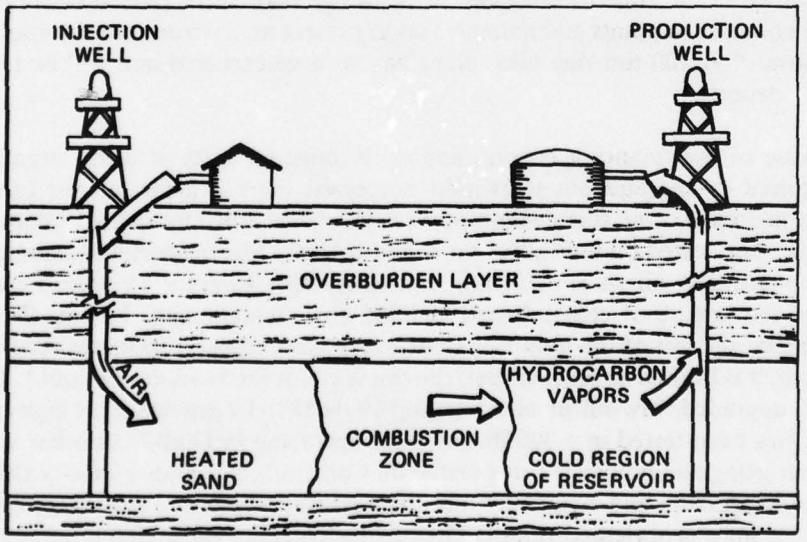
Because of the financial, energy, and environmental costs of using large amounts of water required by the aqueous extraction processes, there is great interest in dry surface extraction processes. One such technology has been developed by United International Research, Inc., and tested on low-sulfur tar sands in Utah. The process is somewhat similar to internal combustion oil shale retorting technology (see Chapter 5). Mined tar sands are crushed to the texture of coarse lumps and fed into a rotary kiln. Part of the bitumen is burned to heat the rest of the bitumen, from which gas and oily vapors are recovered. Some of the product is burned as process fuel; the rest is condensed as a gas or liquid. The liquid is a partially upgraded, low-sulfur oil averaging 19 to 25°API gravity. This high-temperature technique has been tested in a 500 lb/day pilot operation in Utah.[21] In other work, Lurgi-Ruhrgas retorting technology is being tested on California tar sands by Getty Oil Company. Underwood McLellan and Associates and the Alberta Oil Sands Technology and Research Authority, using a proprietary rotating kiln, are testing a dry extraction process on tar sands in Calgary, Alberta.

In-Situ Extraction

Since the bitumen in tar sands deposits is too viscous to flow through the ground to a well and to be pumped to the surface, in-situ extraction processes try to reduce the viscosity of the bitumen underground so that it can be produced through wells. In-situ extraction processes use predominantly thermal methods to mobilize and recover bitumen. Thermal methods of recovering bitumen from tar sands deposits include in-situ combustion and various steam applications.

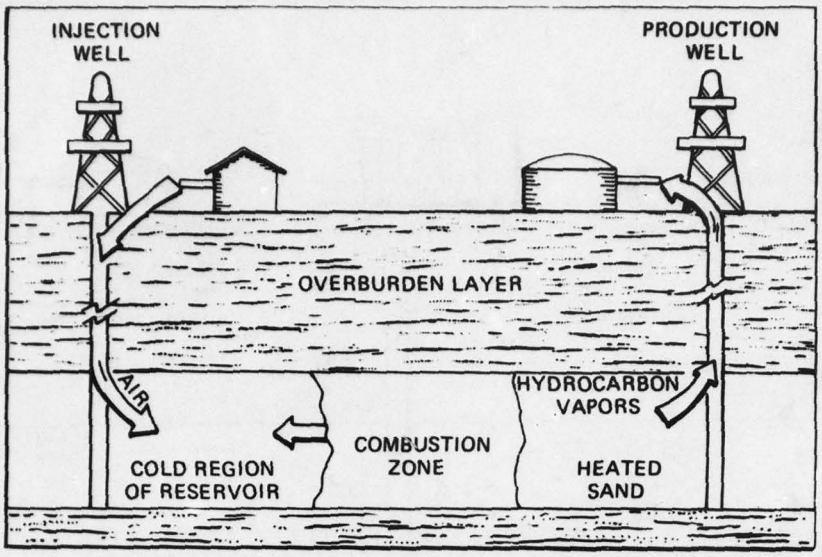
In-situ combustion processes burn part of the bitumen to heat the deposit to temperatures high enough to vaporize the rest of the bitumen. These processes are designated as forward or reverse combustion, depending on the movement of the combustion front relative to the flow of air injected to maintain combustion. In forward combustion operations (Figure 6-8), the deposit is ignited near the air injection well and the combustion front moves from the injection well toward producing wells. The hydrocarbon vapors produced by combustion move ahead of the combustion front, through an unheated zone, toward a producing well where they are collected. The unheated zone can cool and therefore condense the liquid and vapors, clogging the openings in the deposit and preventing the flow of products to a well. In reverse combustion (see Figure 6-9), the deposit is ignited near the producing well, air is introduced through the injection well, and the combustion front moves from the producing well toward the injection well by heat conduction. In this process, the oil and vapor products remain in a heated area while moving toward the producing well, which minimizes clogged openings in the formation and recovers high yields of bitumen.

LETC has been testing in-situ reverse combustion processes since 1975 in the northwest



Source: C. Q. Cupps, C. S. Land, and L. C. Marchant, "Field Experiment of *In-Situ* Oil Recovery from a Utah Tar Sand by Reverse Combustion," *Oil Shale and Tar Sands,* AIChE Symposium Series, Vol. 72, No. 155, 1976.

Figure 6-8. FORWARD COMBUSTION PROCESS



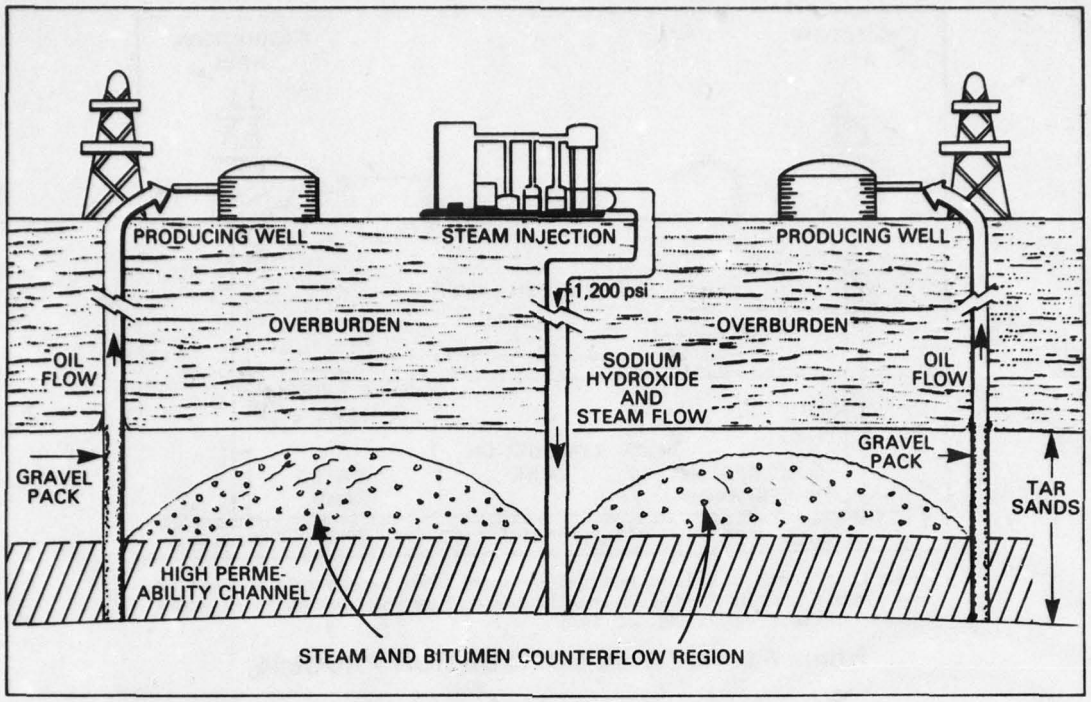
Source: C. Q. Cupps, C. S. Land, and L. C. Marchant, "Field Experiment of *In-Situ* Oil Recovery from a Utah Tar Sand by Reverse Combustion," *Oil Shale and Tar Sands,* AIChE Symposium Series, Vol. 72, No. 155, 1976.

Figure 6-9. REVERSE COMBUSTION PROCESS

Asphalt Ridge tar sands deposit. The first field test operated for only 23 days, but it confirmed the technical feasibility of reverse combustion and specified process and mechanical problems. A second test was made that preheated a tar sands zone by reverse combustion and then allowed the combustion front to echo back through the zone in the forward mode for more thorough heating and oil recovery. The second test indicated the need for greater permeability in the tar sands zone.[22]

Many in-situ recovery techniques use steam to produce oil from bitumen. Some processes steam flood or soak the deposit, and some use a cyclic steam injection method of moving oil out of tar sands. Steam soak is a long-term process that requires about 3.5 years of work on the deposit before any oil is produced. First, steam is injected into the designated deposit daily until breakthrough. The time required for this operation varies with the site being exploited. The work by Shell Canada, Ltd., on a Peace River deposit took 2 years (Figure 6-10). Once breakthrough is experienced, steam injection is continued until the deposit is thoroughly heated—another 1.5 years at Peace River. Then the pressure in the formation is reduced and production begins. Production may continue for 1.5 years. Shell Canada's operation used about 0.5 ton of steam/bbl of bitumen recovered.[14] The ratio of steam consumed to barrels of bitumen produced indicates the degree of energy efficiency of the technology.

Cyclic steam injection, also known as the huff and puff process, alternates steam injection with production. The injected steam permeates the tar sands, heats the bitumen and reduces its viscosity, and drives the mobilized bitumen toward a production well. Then steam injection is halted and the released bitumen is pumped to the surface. Steam is injected again to repeat the process and expand the area of the deposit heated. With enough



Source: Cameron Engineers, Inc., "Tar Sands Deposits of the United States," May 1976.

Figure 6-10. SHELL CANADA IN-SITU RECOVERY PROCESS

steam injections, the areas treated through each injection well overlap and heat the formation more thoroughly.

COMMERCIALIZATION

The United States has been investigating the recovery of bitumen from tar sands on a small scale for about 30 years.[23] Tar sands/heavy oil research is a component of DOE's enhanced oil and gas recovery program. The objectives of the tar sands research conducted at LETC over the last few years have been to determine the feasibility of exploiting tar sands by in-situ recovery methods, classify tar sands deposits regarding properties relevant to the design and operation of in-situ recovery methods, and characterize tar sands bitumens and product oils.[24] LETC is developing technologies for oil recovery from tar sands and characterizing heavy liquids, as well as developing methods for utilizing asphalts.[25] R&D projects in the United States are presented in Table 6-5.

Available technologies for surface mining and extraction are primarily the result of Canadian R&D. The Alberta oil sands have been produced commercially since 1967, when the GCOS surface mining and extraction facility came on stream. Two commercial operations, GCOS and Syncrude Canada, Ltd., are producing 44,300 and 60,000 bbl/day, respectively, of synthetic crude oil out of a combined production capacity of 194,000 bbl/day. Two more commercial ventures have been proposed: a surface extraction plant by the Alsands Project Group (negotiations among the consortium and the governments of Alberta

Table 6-5. U.S. TAR SANDS/HEAVY OIL RECOVERY PROJECTS

Project	Status	Location	Technology	Milestones
American Exploration and Management, Inc.	Proposed	Guadelupe County, New Mexico	Surface extraction (hydrocarbon solvent)	Economic studies on preliminary designs completed.
Carmel Energy, Inc., and DOE	Active	Eastburn Field, Vernon County, Missouri	Vapor therm in-situ recovery of heavy oil	Three wells completed for thermal stimulation.
Chanslor-Western Development Company and DOE	Active	Midway-Sunset Field, California	Steam flooding in-situ recovery of heavy-oil	Production in progress.
Cities Service Company and DOE	Active	Bellevue Field, Louisiana	In-situ combustion (wet)	Production in progress.
Continental Oil Company		Uvalde, Texas	Steam injection in-situ recovery of very low gravity oil	Proprietary research; no information available.
General Crude Oil Company and DOE	Active	Lynch Canyon Field, California	Thermal drive and thermal stimulation recovery of very viscous oil	New project (September 1978).
Getty Oil Company	Proposed	McKittrick Field, California	Surface extraction of bitumen (solvent leaching and/or Lurgi retorting)	Mining and reclamation plans being developed; field testing anticipated in 1980; possible commercial operations by 1984.
Getty Oil Company and DOE	Active	Cat Canyon Field, California	Steam flooding in-situ recovery	Production in progress.
Husky Oil Company and DOE	Active	Paris Valley Field, California	Combination thermal drive and thermal stimulation oil recovery	Production in progress.
Illinois Institute of Technology Research Institute and DOE	Active	Utah	Extraction of oil from tar sands (microwave heating)	New project (November 1978).
Laramie Energy Technology Center (LETC)	Active	Asphalt Ridge, Utah	In-situ combustion and steam recovery	Phase I reverse combustion completed; Phase II reverse then forward combustion completed; Phase III steam process site development in progress.
Ogle Petroleum, Inc.	Active	Monterey County, California	Thermal stimulation recovery of very low gravity oil	Two wells steamed—produced 2° to 3° API gravity oil; evaluation in progress; refining planned.
Oil Development Company of Utah	Proposed	Tar Sand Triangle, Utah	In-situ forward combustion	Project suspended; awaiting resolution of environmental objections to location.
Oil Development Company of Texas and DOE	Active	Willow Draw Field, Wyoming	Attic air injection oil recovery	Project nearing completion; final report being prepared.
Project Deep Steam	Active	Sandia Laboratories	Steam drive in-situ recovery of low-gravity reservoirs below 760 m	
Toluco, Inc., and Permaloy Corporation	Proposed	Utah	Surface extraction (organic solvent)	Laboratory tests completed.

Sources: U.S. Department of Energy, "Contracts and Grants for Cooperative Research on Enhanced Oil and Gas Recovery and Improved Drilling Methods, Progress Review No. 16," BETC-78/4, December 1978; and United International Research, Inc., "Preliminary Report on the Treatment of the Athabasca Oil Sands for the Purpose of Extraction of the Bitumen Content," February 1976.

and Canada on taxes and product prices are under way)[26] and the first in-situ recovery facility by Imperial Oil, Ltd. Table 6-6 lists commercial tar sands oil recovery operations in Canada.

Unlike the governments of Alberta and Canada, the U.S. government has not offered incentives for commercial exploitation of tar sands resources. Additionally, the Athabasca deposits have greater levels of bitumen saturation, more homogeneous properties, and greater volumes of oil in place in a localized area than U.S. deposits. These qualities allow for economies of scale unavailable to U.S. plants, which are likely to produce 10,000 to 25,000 bbl/day as opposed to the 100,000 to 125,000 bbl/day probable in Canada. Also, the isolated location of the Athabasca deposits reduces the need for and costs of environmental protection.[3]

There has never been any commercial production of U.S. tar sands for synthetic fuels (tar sands have been commercially mined for paving asphalt), nor are tar sands in the United States currently recognized as a commercially feasible source of energy.[27] Although six tar sands deposits in Utah hold adequate quantities of oil to support relatively large production, various technical, environmental, economic, and institutional factors inhibit the commercialization of U.S. tar sands. Primary factors limiting the growth of a U.S. tar sands industry include a limited resource base and lack of resource information, lack of a workable tar sands leasing policy, the state of the technology, water availability, rapidly increasing operating costs, and lack of subsidies or guaranteed prices for synthetic fuels.[28]

ENVIRONMENTAL ISSUES

Commercial operations in Canada and pilot studies in the United States have provided information on the environmental impacts of producing oil from tar sands. All of the extracting and upgrading technologies create air and water emissions, solid wastes, and surface changes, although the type and magnitude of each vary. According to the Environmental Protection Agency (EPA), obtaining oil from tar sands will affect the environment by:

Table 6-6. COMMERCIAL TAR SANDS OIL RECOVERY OPERATIONS IN CANADA

Company	Location	Technology[a]	Capacity (bbl/day)	Status
Great Canadian Oil Sands Ltd. (GCOS)—Sun Oil Company	Athabasca Deposit, Ft. McMurray	M: Bucketwheel excavators E: Hot water process	65,000	Operational since 1967; 1977 average production was 44,300 bbl/day.
Syncrude Canada Ltd.—Imperial Oil Ltd., et al.	Athabasca Deposit	M: Electric draglines E: Hot water flotation process	129,000	Plant virtually completed; officially opened September 1978; current production is 60,000 bbl/day.
Alsands Project Group—Shell Canada, et al.	Athabasca Deposit	M: Electric draglines E: Hot water process	125,000	Proposed plant being negotiated with governments of Alberta and Canada.
Imperial Oil, Ltd.	Cold Lake Deposit	In-situ steam-driven recovery	141,000	Proposed plant; application being considered by Alberta's Energy Resources Conservation Board.

[a]M—mining; E—extraction.

Source: Cameron Engineers, Inc., "Synthetic Fuels," Vol. 15, No. 4, December 1978.

- Polluting the air with gaseous and particulate emissions from mining, in-situ combustion, hauling and handling of materials, diesel equipment, and upgrading plants (steam boilers, sulfur plant, cokers).
- Possibly requiring large quantities of water for dust control, cooling product fluids, and in-situ methods of steam flooding and wet combustion—operations that would contaminate the water.
- Producing wastewater along with oil in some in-situ processes.
- Creating solid wastes, such as drill cuttings and spent sand.
- Disrupting the surface by stripping the overburden and mining the resource, building roads and plants, and disposing of waste sand.
- Disturbing the wildlife habitat.[23]

Many of these environmental impacts are similar to those accompanying coal mining and petroleum production, and thus, environmental protection measures developed for those operations can be used to limit the environmental effects of producing tar sands oil. Gaseous emissions can be detoxified by vapor recovery or flaring at in-situ sites and upgrading plants, and by flue gas desulfurization for steam boilers. Electrostatic precipitators can remove fly ash particulate emissions from fluid cokers at upgrading plants. Wastewater can be treated and reused in surface facilities or reinjected into in-situ sites. Waste sand can be returned to mines or stored on the surface and revegetated.[23]

Environmental impacts vary somewhat with the production and extraction technology employed (see Table 6-7). Surface mining methods present greater possible impacts than underground mining because of the problems of disrupting and restoring large areas of land. All mining methods present greater possible impacts than in-situ recovery methods because of the problems of spent sand disposal and additional wastes from aboveground extraction plants. Environmentally, in-situ production of tar sands is more benign, and therefore, more acceptable. However, knowledge of the effects of in-situ extraction is limited and further research may change the verdict.[23]

Table 6-7. ENVIRONMENTAL COMPARISON OF POTENTIAL TAR SANDS PRODUCTION AND EXTRACTION METHODS

Operation or Process	Status of Tar Sands Technology	Major Potential Technical Disadvantages or Environmental Impacts	Major Potential Technical or Environmental Advantages
Surface mining	Two commercial operations in Canada; others planned or proposed. Small scale open-pit projects in United States. No large-scale demonstration of technology in United States.	Most potential for surface changes during mining. Least potential for complete restoration of surface to premining condition. Requires removal and transportation of tar sands. Disadvantages include those of extraction. Most potential for increasing availability of aqueous transportable materials. Generates most solid waste (mine waste plus spent sand). Greatest materials handling requirements (solid waste plus tar sands).	Basic surface mining technology applicable. High to highest bitumen recovery.
Underground mining	Applicability of available underground mining technology not yet investigated.	Requires removal and transportation of tar sands. Creates potential for surface subsidence. Disadvantages include those of extraction.	Can draw from available underground mining technology. Potential for underground disposal of spent sand. High bitumen recovery (longwall method of mining). Least potential (among mining methods) for surface changes during mining. Best potential (among mining methods) for minimizing permanent surface changes if no subsidence and spent sand returned to mine. Eliminates stripping operation and resultant solid wastes.
Longwall stripping	Applicability to tar sands not yet investigated.	Requires removal and transportation of tar sands. Disadvantages include those of extraction. If used after contour mining, would probably increase potential for environmental impact.	Applicability of method for mining of coal under investigation. Total potential for environmental impact probably less than that of other methods of mining same amount of sands. If used after contour mining, could recover greater percentage of tar sands deposit.

Table 6-7. ENVIRONMENTAL COMPARISON OF POTENTIAL TAR SANDS PRODUCTION AND EXTRACTION METHODS (CONT'D)

Operation or Process	Status of Tar Sands Technology	Major Potential Technical Disadvantages or Environmental Impacts	Major Potential Technical or Environmental Advantages
Extraction of bitumen from mined tar sands	Wet process: Two commercial operations in Canada; others planned or proposed. Small scale or bench tests in United States. Retorting: Applicability to tar sands generally unevaluated experimentally.	Wet process: Generation and disposal of solid wastes (spent sand). Availability of water if process water not reused. Leached constituents in waste water effluents. Retorting: Availability of water for once-through cooling systems. High temperature could result in more contaminants in syncrude than wet processes.	Wet process: Could result in less contaminants in syncrude than retorting. Retorting: Could be less potential for water pollution than in wet processes.
In-situ production	No commercial production to date from tar sands. Pilot projects have been conducted but in-situ technologies for commercially producing tar sands are not yet demonstrated.	Nonuniform nature of tar sands characteristics poses technical problems. Bitumen recovery expected to be less than that for surface mining. Availability of water unless coproduced water treated and reused (depending on location and method).	Basic technologies include those of producing heavy oil reservoirs. Produces tar sands that are too deep to be produced economically by mining methods. Eliminates generation of solid waste of mining and spent sand from extraction process. Some upgrading of tar sands bitumen could occur underground. Coproduced waters could be disposed of or treated and reused in water-short areas. Disturbs much less surface area than surface mining. Eliminates potential sources of dust and noise in surface mining operation.

Source: U.S. Environmental Protection Agency, "Production and Processing of U.S. Tar Sands: An Environmental Assessment," EPA-600/7-76-035, December 1976.

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7. NUCLEAR ENERGY

Nuclear fuels have a very high energy content per unit mass or volume, and some can produce new fuel as the initial fuel is being used. Power is generated from nuclear reactions by two distinct processes. The more highly developed method is nuclear fission. In the fission process, heavy nuclei, such as those of uranium and plutonium atoms, are split into lighter nuclei by neutron absorption. The splitting of the heavy nuclei results in the release of additional neutrons (which sustain the fission process) and the conversion of a small fraction of mass into kinetic energy of the fission products. This kinetic energy is degraded into thermal energy and the fission process acts simply as a heat source to make steam to generate electric power. Although the basic process is conceptually simple, the engineering, control, and safety considerations make fission utilization a highly sophisticated industry, requiring the integration of a great many technologies.

The second process using nuclear reactions for power generation is fusion. Fusion is much the opposite of fission in that light nuclei, such as those of the hydrogen isotopes deuterium and tritium, are combined (or fused) into heavier nuclei, such as those of helium. This process is similar to that occurring within the sun. Again, a small amount of mass is converted into kinetic energy that can be degraded into useful thermal energy. The process is conceptually simple, but technically difficult, because fusion can occur only under the stringent conditions of ultrahigh temperatures (100,000,000°K) for the appropriate fuel confinement time and density.

Basically two approaches are employed to achieve the conditions necessary for fusion. The first is magnetic confinement of a heated plasma; several magnetic configurations that make fusion temperatures attainable are being investigated. The second approach to fusion is to produce microimplosions by subjecting pellets of a deuterium-tritium mixture to intense bombardment by electron beams or laser beams. Power generation by means of fusion is not a near-term possibility. Many basic problems, requiring substantial private and public investments in research, must be solved.

NUCLEAR POWER GROWTH

The commercial nuclear electrical energy generating capacity in the United States is based on light water reactor (LWR) systems. As of 1 October 1978, there were 70 LWRs licensed for operation by the Nuclear Regulatory Commission (NRC). The total capacity of these plants is 51,511 MWe or about 12 percent of the total electric generating capacity in the United States. In addition, construction permits have been issued for 88 new plants that will have a total capacity of 95,954 MWe. When these plants are operational, the overall U.S. nuclear electric generating capacity will be 147,465 MWe.[1]

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The growth rate of installed nuclear capacity in the United States is a function of the economic conditions of the utilities and of permitting and construction delays. Delays encountered by the electric utilities have stemmed from environmental objections, complex licensing procedures, and construction and supply limitations. About 10 to 12 years are required from the time a nuclear plant is ordered until it begins operating. The growth rate of the U.S. nuclear power industry has been about 15 percent/year over the last 5 years; however, this rate is expected to decline in several years because there have been more cancellations of reactors than orders in the past 2 years.

Outside the United States, 19 countries operate nuclear reactors for electric power generation and an additional 14 countries have nuclear power reactors on order or under construction. The leading non-U.S. users of nuclear power are Japan, the Soviet Union, the United Kingdom, West Germany, France, and Canada, as shown in Table 7-1.[2]

Table 7-1. NUCLEAR POWER PLANT CAPACITY IN THE LEADING NUCLEAR NATIONS

Country	Total Capacity (MWe)	Number of Power Plants	Average Plant Capacity (MWe)
United States	51,511	70	736
Japan	9,277	16	580
Soviet Union	8,475	22	385
United Kingdom	8,080	33	245
West Germany	6,105	10	611
France	4,598	12	383
Canada	4,482	9	498

Source: *Nuclear News,* August 1978.

The ability to meet long-term nuclear capacity projections depends greatly upon the introduction of several new types of reactors. The reason for this limitation is the finite amount of uranium available from which LWR fuel is obtained. The two alternative reactors discussed most widely are the liquid metal fast breeder reactor (LMFBR) and the high-temperature gas-cooled reator (HTGR). Both of these reactors can greatly extend the resource base. The United States has a capacity for producing both of these reactors.

U.S. study and testing experience with LMFBRs dates back to 1946; these efforts resulted in the first nuclear powered electrical energy in the world produced from an LMFBR on 20 December 1951 at the National Reactor Test Station (now the Idaho National Engineering Laboratory).[3] The Fort St. Vrain 330 MWe HTGR operated by the Public Service Company of Colorado still is being tested. Germany is building a 300 MWe steam cycle HTGR demonstration plant that will generate process heat or operate a helium gas turbine.

NUCLEAR FUEL RESOURCES

Estimates of identified resources of uranium and thorium in the United States and other countries that have reported such resources are shown in Tables 7-2 and 7-3. The exact extent of thorium deposits is not well known, but minable thorium is probably as abundant as uranium. The resource base of uranium and thorium for the nuclear industry commonly is expressed in terms of tons of the resource recoverable at a given cost, as shown in Tables 7-4 and 7-5. These latter estimates do not agree closely with those provided in Tables 7-2 and

Table 7-2. IDENTIFIED URANIUM RESOURCES[a]

Country[b]	Percent U_3O_8	Metric Tons U_3O_8
United States	0.22	247,660
Argentina	>0.10	8,160
Australia	>0.10	90,700
Canada	>0.10, <0.10[c]	326,580
Central Africa Republic	~0.10	17,690
France	>0.10	60,240
Gabon	>0.10	17,690
India	0.06-0.07	32,660
Japan	0.06	3,630
Mexico	>0.10	2,160
Niger	0.29, >0.10[d]	35,470
Portugal	>0.10	8,620
South Africa, South West Africa	<0.10	272,150
Spain	>0.10	9,980
Sweden	0.03	317,510
Other Europe (West Germany, Italy, Turkey, Yugoslavia	>0.10	5,900
Total world identified resources	—	1,456,800

[a]Identified resources are specific, identified mineral deposits that may or may not be evaluated as to extent and grade, and whose contained minerals may or may not be profitably recoverable with existing technology and economic conditions.

[b]Countries that have reported resources are listed.

[c]Includes 208,650 metric tons having grade >0.10 percent U_3O_8 and 117,930 metric tons having grade <0.10 percent U_3O_8.

[d]Includes 23,590 metric tons having grade 0.29 percent U_3O_8 and 11,880 metric tons having grade >0.10 percent U_3O_8.

Source: U.S. Geological Survey, Professional Paper 820, 1975.

7-3 for U.S. resources, indicating that the exact size of these resources has not been precisely identified.

Uranium could be recovered from unconventional sources in the United States at costs of $100/lb of uranium ore concentrate (U_3O_8), including 2.5 million metric tons from low grade ore and an additional 2.3 million metric tons from Chattanooga shale. Also, uranium may be recovered from seawater (0.0033 ppm U) at a cost of about $300/lb U_3O_8.[4]

U.S. NUCLEAR FUEL DEMAND

In the long term, the demand for U_3O_8, called yellowcake, will depend on the types of reactors in operation, the availability or unavailability of reprocessing facilities and the plutonium recycle, and the assay of the depleted uranium at the enrichment facilities. Actual purchase commitments fluctuate greatly from year to year. In 1975, U.S. utilities were committed to purchase 13,150 metric tons of yellowcake, whereas 1976 commitments were for 75,750 metric tons; in 1977, purchase commitments were for 10,430 metric tons of yellowcake.[5]

Consumption of yellowcake by U.S. utilities in 1978 is expected to be 10,900 to 11,800 metric tons. In 1980, consumption is expected to be 12,700 to 14,500 metric tons, and will climb to 31,750 to 40,800 metric tons of yellowcake per year by 1990 if projections of nuclear power growth prove to be true and if there is no uranium reprocessing or plutonium recycle.[6]

At the end of 1973, 15 uranium ore mills were operating or on standby in the United States, with a total capacity to process 25,800 metric tons of U_3O_8 per year.[7] In 1975, the United States produced 11,160 metric tons of yellowcake; primary demand for nuclear fuels was estimated at 14,150 metric tons.[8]

As a result of supply and demand for uranium, the price of U_3O_8 has increased dramatically since 1973. The average market price of uranium for 1978 delivery was $43.65/lb of U_3O_8. However, the average price of U_3O_8 delivered was $18.50/lb because of longer-term contractual arrangements between the mining industry and the utilities. Only 13 percent of the yellowcake delivered was purchased at the market price.[9]

Table 7-3. IDENTIFIED THORIUM RESOURCES[a] (Thousands of metric tons)

Country	Recoverable Primarily As By-Product or Coproduct	Recoverable Primarily for ThO_2 By Grade	
		>0.1 Percent	<0.1 Percent
United States	41.7	96.6	128.8
Australia	45.3	–	–
Brazil	136.0	12.7	–
Canada	526.1	–	–
Greenland	–	–	680.4
India	408.2	–	–
Kenya	19.0	–	–
Korea	5.4	–	–
Malagasy Republic	9.0	–	–
Malaysia	18.1	–	–
Malawi	–	–	9.0
South Africa	68.0	–	–
Uganda	1.8	–	–
United Arab Republic	9.0	–	–
West Africa	13.6	–	–
Total world identified resources	1,301.2	109.3	818.2

[a]Identified resources are specific, identified mineral deposits that may or may not be evaluated as to extent and grade, and whose contained minerals may or may not be profitably recoverable with existing technology and economic conditions.

Source: U.S. Geological Survey, Professional Paper 820, 1975.

Table 7-4. U.S. URANIUM RESOURCES

Recovery Cost ($/lb)	Resource (Thousands of metric tons)			
	Reserves	Probable	Possible	Speculative
0-15	336	490	445	150
15-30	290	413	585	227
30-50	181	345	345	136

Note: U_3O_8 as a by-product of phosphate and copper production amounts to 127,000 metric tons in reserve.

Source: U.S. Department of Energy, Division of Nuclear Power Development, "Update, Nuclear Power Program Information and Data," June 1978, p. 10.

The capital-intensive nature of the nuclear industry makes the cost of power produced almost independent of uranium costs. A $10/lb increase in the price of yellowcake increases the total fuel cycle cost about 0.8 mill/kWh.[2] Also, uranium supplies have been committed to long-term procurement contracts within the nuclear industry so that the current market price is not an accurate indicator of actual costs to the buyer.

NUCLEAR FUEL CYCLE

Use of nuclear fuels differs from that of fossil fuels in two important ways:

- Nuclear fuel must undergo a complex series of processing steps to produce useful fuel elements.
- Nuclear fuels are not expended completely when used in a reactor, and can be reprocessed for recycling.

Table 7-5. U.S. THORIUM RESERVES

Recovery Cost ($/lb)	Reasonably Assured Reserves (Thousands of metric tons)
0-10	59.4
10-30	122.5
30-50	2,721.5

Source: U.S. Atomic Energy Commission, Draft Environmental Statement: Liquid Metal Fast Breeder Reactor Programs, WASH-1535, 1974.

These unique characteristics establish a fuel cycle that includes mining, milling, conversion, enrichment, fabrication, reprocessing, and waste management. Figure 7-1 shows fuel cycles for the light water reactor (LWR), high-temperature gas-cooled reactor (HTGR), and liquid metal fast breeder reactor (LMFBR). Uranium-235, uranium-233, and plutonium-239 are the three fissile materials capable of serving as fuels in fission reactors. The LWRs in use in the United States are designed to operate on "enriched" uranium that contains 2.0 to 3.2 percent U-235, although reactors such as the Canadian CANDU can operate on natural uranium, which contains about 0.7 percent U-235.

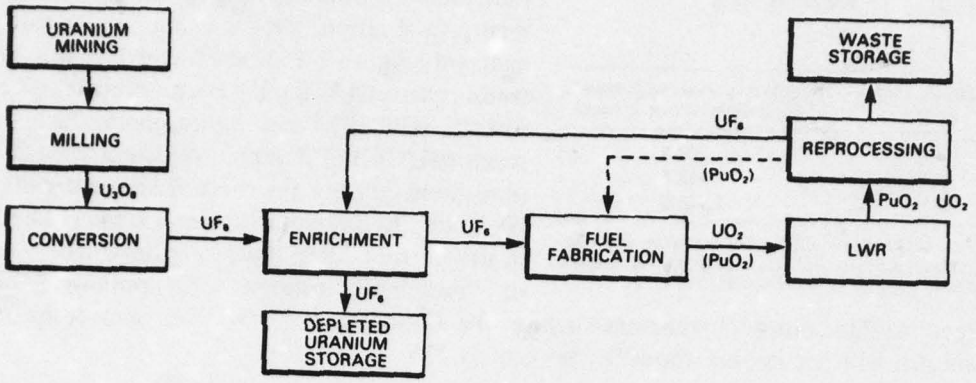
The HTGR uses a more highly enriched fuel consisting of a mixture of about 5 percent U-235, 95 percent Th-232, and less than 1 percent U-238. By using a mixture of both fissionable (U-235) and fertile (Th-232 and U-238) isotopes in the HTGR, it is possible to reduce the rate of depletion of the nuclear fuel, because capture of excess neutrons by the fertile materials replenishes the fissionable material. In the HTGR, excess neutrons from the U-235 fission are absorbed by the thorium nuclei in thorium carbide (ThC_2) to produce the fissile U-233.

The LMFBR fuel cycle uses plutonium-239 as a fuel. The U-238 in the natural uranium that serves as the resource base provides the fertile material from which the plutonium is bred. The unique feature of the LMFBR fuel cycle is that more plutonium is bred from the U-238 than is consumed in the reactor. In the sense that plutonium is the fissioning material, more fuel is produced than is consumed, and the excess plutonium can be used in other reactors, such as the LWR. In the LWR fuel cycle shown in Figure 7-1, the dashed line indicates the path the plutonium would follow if it were to be recycled for use as LWR fuel.

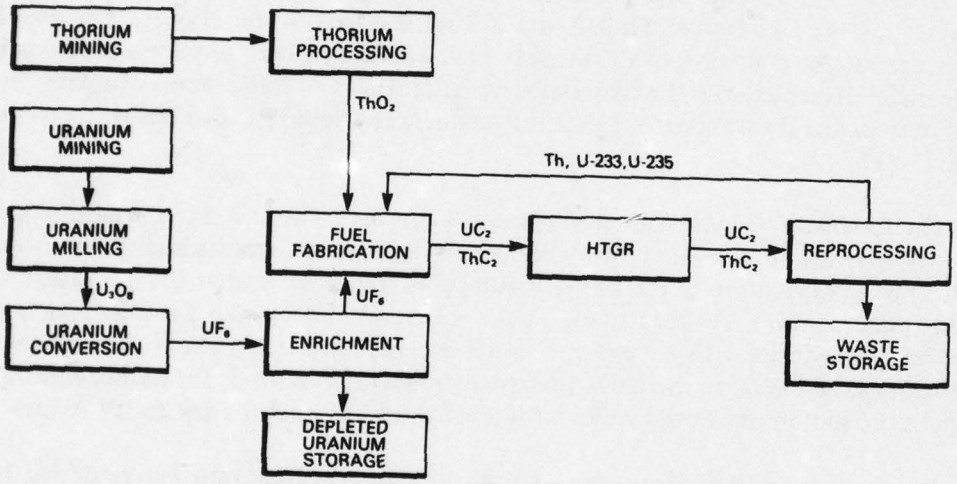
Periodically (usually once a year), LWRs are shut down and refueled, replacing 25 to 35 percent of the fuel. The spent fuel, which is intensely radioactive, is stored under water at the power plant site for several months before it is shipped to a reprocessing plant. At the present time, however, the nuclear fuel cycle in the United States is incomplete because no facilities are operating to reprocess commercially generated spent fuel. Instead, U.S. nuclear power reactors operate on a once-through cycle; the spent fuel rods are stored. Uranium and plutonium reprocessing has been deferred indefinitely by the federal government because of concern over nuclear safeguards. Therefore, most U.S. nuclear power plants are expanding their storage capacity until ultimately there is a repository for spent fuel.

NUCLEAR FUEL PROCESSING

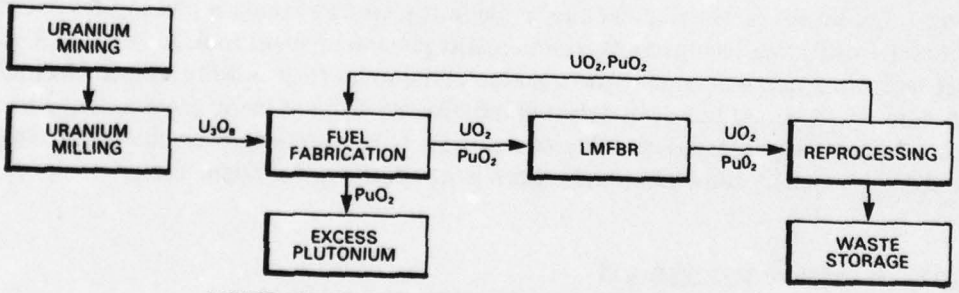
Of the three fissile materials capable of serving as fuels in fission reactors, only U-235 occurs naturally. The other two materials can be produced (or bred) by neutron absorption from the fertile materials thorium-232 and uranium-238. Most uranium ores contain about 0.1 to 0.3 percent U_3O_8; uranium, as it occurs naturally, is 99.284 percent U-238, 0.711 per-



LIGHT WATER REACTOR FUEL CYCLE



HIGH TEMPERATURE, GAS-COOLED REACTOR FUEL CYCLE



LIQUID METAL FAST BREEDER REACTOR FUEL CYCLE

Figure 7-1. LWR, HTGR, AND LMFBR FUEL CYCLES

cent U-235 (the fissionable isotope that serves as the basic energy source), and 0.005 percent U-234.

Uranium ore is mined and milled to obtain yellowcake. Because of the variety of natural sources of uranium, no one concentration method is suited uniquely to all ores. Concentration by gravity methods, for example, is applicable for pitchblende but not for carnotite or autunite, from which uranium is extracted almost exclusively by leaching with acid or alkali carbonate followed by precipitation of the oxide concentrate to yield yellowcake. The yellowcake, which is 85 to 88 percent uranium oxide and contains only 0.6 percent U-235, is shipped from the mill to a conversion plant in 55 gal. drums in accordance with NRC regulations. (This material presents little radioactivity hazard, but its heavy metal concentration renders it toxic if ingested or inhaled.)

At the conversion plant, the yellowcake is converted to uranium hexafluoride (UF_6), a solid at room temperature. Two plants currently are operating in the United States to convert yellowcake to UF_6. These plants can process 20,320 metric tons of yellowcake per year to produce 25,500 metric tons of UF_6 per year. Planned expansion of an existing facility and construction of a new plant would double the U.S. conversion capacity (although this would not be needed until about 1980). The costs of conversion amount to about 1.5 percent of the cost of the total fuel cycle and have little effect on the cost of power produced.

The UF_6 is shipped to an enrichment facility. Enrichment, a major component of the fuel cycle, involves changing the ratio of the uranium isotopes (U-235 and U-238). The portion of UF_6 that contains a higher than natural percentage (or assay) of U-235 is the enriched uranium, and the portion that contains the lower assay is the depleted uranium (or tails). The U.S. Department of Energy (DOE) operates three gaseous diffusion plants that alter the isotopic mixture of U-235 and U-238 in UF_6. The gaseous diffusion process is both capital and power intensive. The capacity and productivity of the enrichment process are measured in terms of separative work units (SWU). An SWU is a measure of the effort expended in the plant to separate a quantity of uranium of a given assay into two components, one having a higher percentage of U-235 and one having a lower percentage. Separative work generally is expressed in kilograms to give it the same dimension as material quantities. However, it is common practice to refer to a kilogram SWU simply as an SWU. For example, if 1 kg of uranium enriched to 3.0 percent U-235 were produced starting with natural uranium (0.711 percent U-235) and with depleted uranium (or tails) of 0.275 percent U-235, then 3.6 SWU would be required. Any change in the feed assay, the tails assay, or the enrichment assay would change the number of SWU. For the example cited, 6.25 kg of natural uranium are needed to produce 1 kg of 3.0 percent enriched uranium.[10] Lowering the tails assay would decrease the demand for natural uranium but would increase the separation work required. DOE operates its diffusion plants at 0.25 percent tails assay.[11]

The three U.S. enrichment plants—located at Oak Ridge, Tennessee; Paducah, Kentucky; and Portsmouth, Ohio—operate interdependently with a total capacity of 17.2 million SWU/year. Operating at full capacity, the three plants consume 6,000 MWe. Because the demand for enrichment services will grow with the nuclear power industry, DOE is pursuing two programs to increase the diffusion plant capacities: the Cascade Improvement Program will increase capacity by 33 percent, and the Cascade Uprating Program will raise that capacity another 21 percent for a total of 27.7 million SWU/year by 1980.

As of 30 December 1978, the cost of enrichment at these plants was set at $88.65/SWU for fixed-commitment contracts, under which utilities specify in advance the amount of services required over a 10 year period. On 24 April 1979, the present price of $83.15/SWU for requirement contracts will be increased to $98.30/SWU. (Such contracts obligate DOE, within limits, to provide a utility with the amount of services needed.)[12] An increase of $10/SWU increases the fuel cycle costs by about 0.3 mill/kWh.[13] To minimize the overall cost of a nuclear plant, its core is designed based on the cost of enriching the uranium.

Gaseous diffusion plants consume vast amounts of electrical energy. Consequently, DOE's planned enrichment facility applies a technology that requires only one-tenth as much power as that needed for gaseous diffusion. The technology employs a gaseous centrifuge, which has been demonstrated successfully in both the United States and England. Construction of the new centrifuge enrichment plant was started in Piketon, Ohio, in 1978. The total cost of the plant will exceed $1 billion.[14]

European countries also are expanding their capacity. Seven western European countries joined together in 1977 to study the feasibility of building a diffusion plant with a capacity of 6 million or 7 million SWU/year for uranium enrichment. Through joint efforts of the United Kingdom, the Netherlands, and West Germany, a 200,000 SWU/year centrifuge enrichment plant was built in England, and another 200,000 SWU/year plant is to be built in the Netherlands.

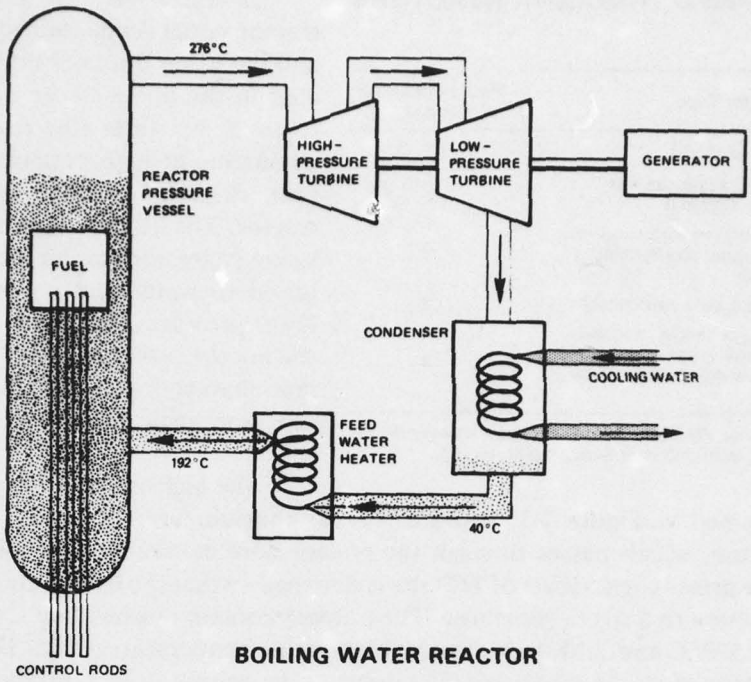
Isotope separation by lasers is another technology that could reduce enrichment costs. This technology, still in the experimental stage, is considered to be a possible long-term enrichment method.

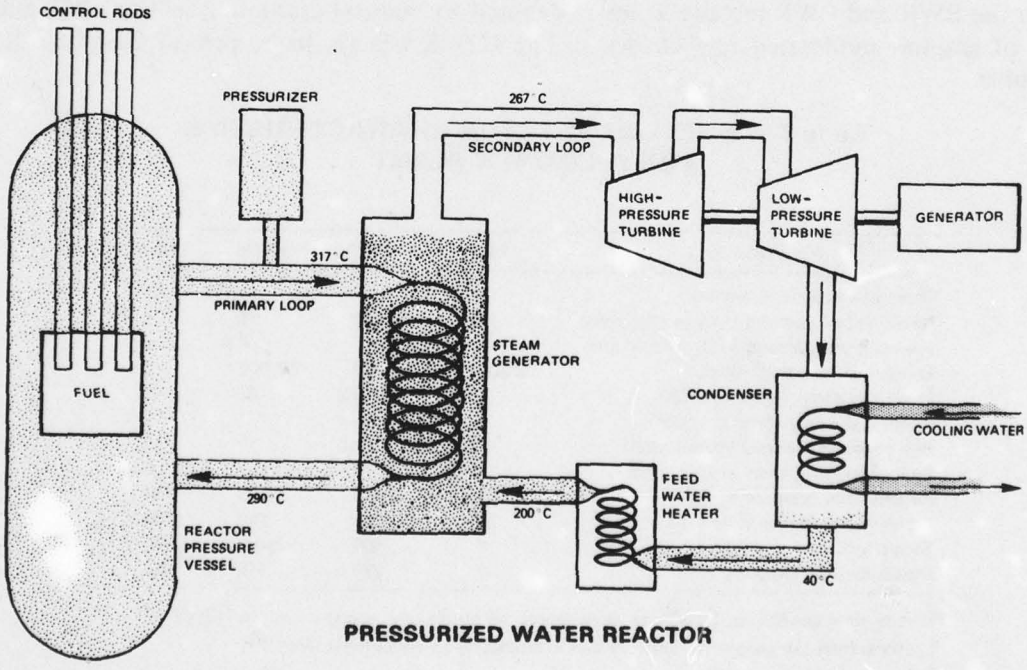
The enriched uranium is shipped to a fuel fabrication plant for conversion into uranium oxide (UO_2) powder. The powder is compacted into small, precisely dimensioned, cylindrical pellets. The pellets are sintered, then, for most reactor applications, are loaded into zircaloy (LWRs) or stainless steel (breeder reactors) tubes that are welded shut. The completed fuel rods are precisely aligned into fuel element arrays, which are shipped to a nuclear power plant. Five fuel fabrication plants are operating in the United States with a total capacity of 2,744 metric tons of uranium per year.[13]

NUCLEAR REACTORS

Nuclear power reactors now operating around the the world (or ordered for start-up by 1980) are of the types listed in Table 7-6. Light water nuclear fission reactors are of two principal designs: boiling water reactors (BWR) and pressurized water reactors (PWR). Simplified diagrams of BWR and PWR systems are shown in Figure 7-2. Both systems are fueled with slightly enriched UO_2 and cooled by water.

In the BWR, pressure is maintained at about 1,000 psig and boiling takes place in the reactor itself. Steam is generated at 285 °C and passed directly through a turbine to drive an electric generator.





Source: U.S. Atomic Energy Commission, "The Nuclear Industry 1973," WASH-1174-73 UC-2.

Figure 7-2. SCHEMATIC DIAGRAMS FOR BOILING WATER AND PRESSURIZED WATER REACTORS

Table 7-6. TYPES OF NUCLEAR REACTORS

Reactor Type	Percent Installed Capacity
Light water (BWR or PWR)	82
Gas-cooled (or ARG advanced gas-cooled graphite-moderated)	7
Pressurized heavy-water-moderated and cooled (or heavy-water-moderated light-water-cooled)	4
Light-water-cooled graphite-moderated	3
High temperature gas-cooled graphite-moderated (or heavy-water-moderated gas-cooled or liquid-metal-cooled fast breeder)	4

Source: F. S. Aschner, *Planning Fundamentals of Thermal Power Plants* (New York: John Wiley & Sons, 1978), p. 253.

In the PWR, the pressure in the reactor vessel is maintained at 2,050 psig and the water does not boil. Heat generated in the nuclear core of the PWR is removed by water (the reactor coolant) circulating at high pressure through the primary circuit to cool and moderate the reactor. The heated water passes through steam generators where the heat is transferred to water in a secondary loop at lower pressures and steam is formed for driving the turbines. Some of the significant characteristics of these reactor systems appear in Table 7-7.

The high-temperature gas-cooled reactor, diagrammed in Figure 7-3, operates on the thorium/uranium cycle. The primary coolant is helium, which passes through the reactor core consisting of a mixed UC_2 and ThC_2 fuel. The present generation of HTGRs is designed so that the helium coolant transfers the heat of reaction to a steam generator. The primary coolant reaches 760 °C and the steam is generated at 510 °C and 2,400 psig. The high operating temperatures of the HTGR give it a thermal efficiency of nearly 40 percent. If a direct-cycle, helium-driven turbine is developed, the efficiency could be increased to as much as 50 percent.[13] Other advantages of the HTGR over the BWR and PWR include its lower demand for natural uranium (see Table 7-7) and use of graphite-moderated fuel elements. The HTGR has yet to be proved economically feasible.

Table 7-7. NUCLEAR REACTOR CHARACTERISTICS FOR A 1,000 MW PLANT[a]

Characteristics	BWR	PWR	HTGR	LMFBR
Thermal efficiency (percent)	34	33	40	40
Raw material demand U_3O_8 (metric tons)	163	172	91	1.47[b]
Raw material demand ThO_2 (metric tons)	—	—	7.8	—
Enrichment demand[c] (SWU)	84,000	94,000	67,000	—
Fresh fuel assay (percent U-235)	2.7	3.2	93	—
Spent fuel assay (percent U-235)	0.8	0.9	—	—
Reprocessing demand (metric tons)	27	24.5	10	19
Plutonium production (metric tons)	0.16	0.17	—	0.28
Primary loop pressure (psig)	1,000	2,050	700	200
Primary loop temperature (°C)	285	316	760	538
Steam loop pressure (psig)	d	800	2,400	1,450
Steam loop temperature (°C)	d	260	510	482

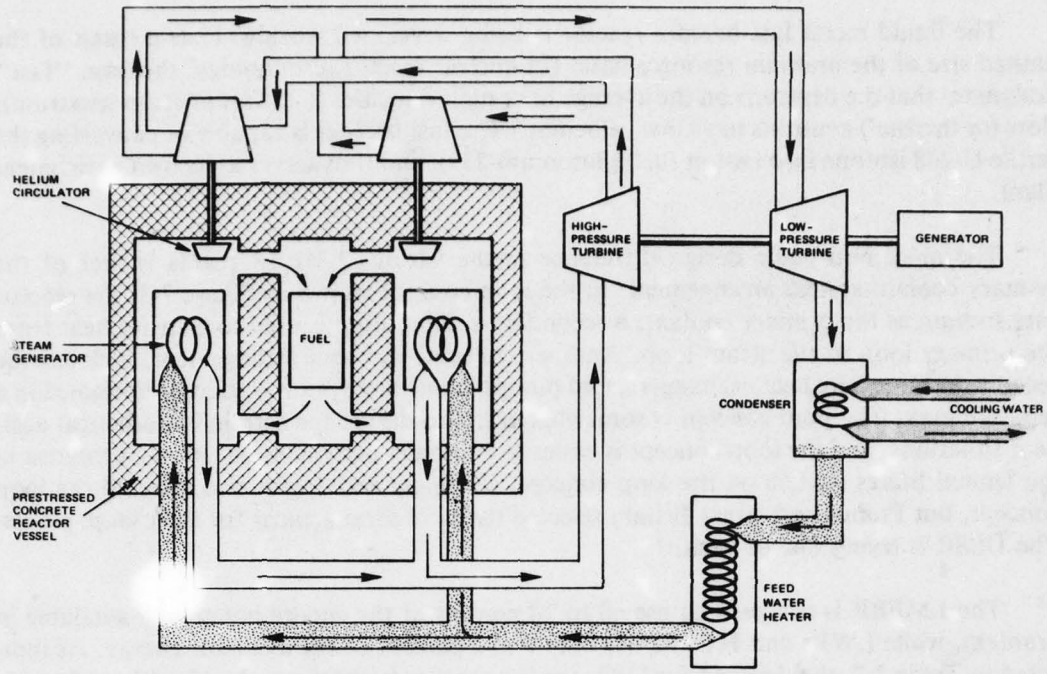
[a]Steady state conditions, 75 percent plant factor, no plutonium recycle except in LMFBR.

[b]Uranium feed can consist of depleted tails in stockpile; no enrichment needed.

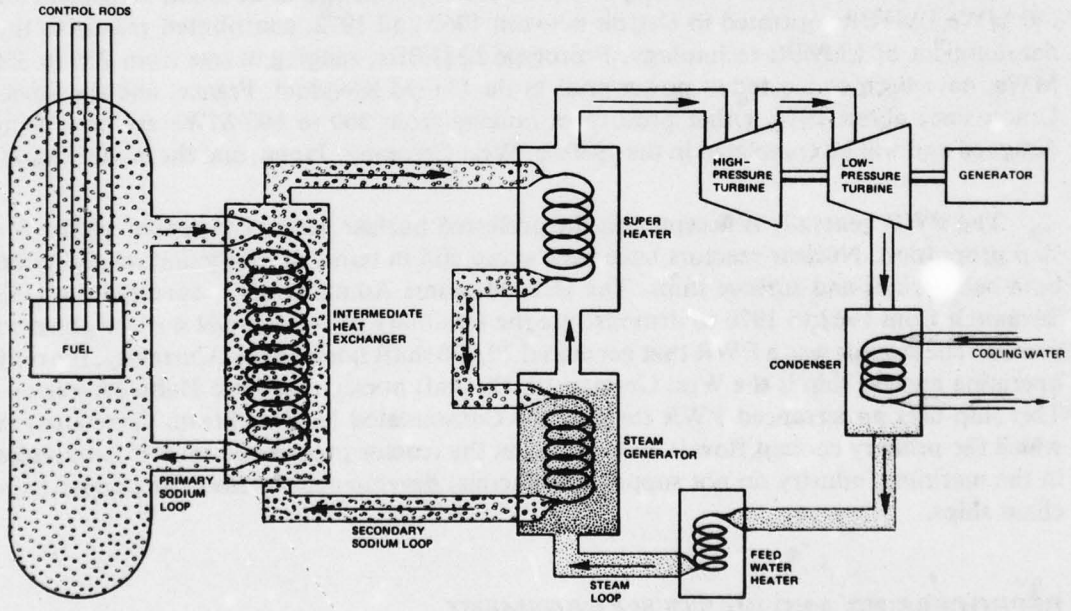
[c]Tails assay 0.30 percent.

[d]There is no secondary loop for a BWR.

Sources: U.S. Atomic Energy Commission, "Nuclear Power Growth 1974-2000," WASH-1139, 1974; U.S. Atomic Energy Commission, "AEC Gaseous Diffusion Plant Operations," ORO-684, 1972; U.S. Atomic Energy Commission, "The Nuclear Industry 1973," WASH-1174-73 UC-2; and U.S. Atomic Energy Commission, "Draft Environmental Statement Liquid Metal Fast Breeder Reactor Program," WASH-1535, 1974.



HIGH TEMPERATURE, GAS-COOLED REACTOR



LIQUID METAL FAST BREEDER REACTOR

Sources: U.S. Atomic Energy Commission, "The Nuclear Industry 1973," WASH-1174-73 UC-2, and "Draft Environmental Statement, Liquid Metal Fast Breeder Reactor Program," WASH-1535-74.

Figure 7-3. SCHEMATIC DIAGRAMS FOR HTGR AND LMFBR REACTORS

The liquid metal fast breeder reactor is being developed worldwide as a result of the limited size of the uranium resource base. (In nuclear reactor terminology, the term "fast" designates that the neutrons on the average have high velocities (i.e., fast neutron spectrum); slow (or thermal) neutrons have low velocities.) The fast breeder is capable of converting the fertile U-238 isotope into fission fuel (plutonium-239), and thus serves as its own enrichment plant.

The most noticeable design difference in the various LMFBR plants is that of the primary coolant system arrangement. In the loop concept shown in Figure 7-3, the reactor uses sodium as the primary coolant; a secondary sodium loop is used to transfer heat from the primary loop to the steam loop. Another concept, the pool arrangement, includes the reactor, intermediate heat exchangers, and pumps in one large pool of sodium contained in a separate tank. The pool concept is somewhat easier to design for certain hypothetical accident situations, and the loop concept is easier to construct and maintain. Primary interest in the United States centers on the loop concept. Germany and Japan also selected the loop concept, but France and Great Britain selected the pool arrangement for their large plants. The USSR is trying one of each.[15]

The LMFBR is designed to use 60 to 70 percent of the energy potentially available in uranium, while LWRs and HTGRs use only 1 to 2 percent of the available energy. As indicated in Table 7-7, the demand for U_3O_8 for the breeder is about one-hundredth of that for LWRs. The overall thermal efficiency of the LMFBR is expected to be about 40 percent. A 140 MWe LMFBR, operated in Detroit between 1962 and 1972, contributed greatly to the development of LMFBR technology. Prototype LMFBRs, ranging in size from 255 to 330 MWe, have been connected to power grids in the United Kingdom, France, and the Soviet Union since about 1974. Other prototypes ranging from 300 to 600 MWe are now being designed and will be completed in the 1980s in West Germany, Japan, and the Soviet Union.

The PWR generally is accepted as the preferred nuclear power conversion system for ship propulsion. Nuclear reactors have been successful in terms of safety and reliability on both submarines and surface ships. The U.S. Maritime Administration operated the USS Savannah from 1962 to 1970 to demonstrate the feasibility of commercial nuclear powered vessels. The reactor was a PWR that generated 20,000 shaft horsepower. Currently, the only operating nuclear ship is the West German 10,000 shaft horsepower Otto Hahn ore-carrier. This ship uses an advanced PWR (termed the Consolidated Nuclear Steam Generator) in which the primary coolant flow is entirely within the reactor pressure vessel.[16,17] Economics in the maritime industry do not support commercial development of fleets of nuclear merchant ships.

REPROCESSING AND WASTE MANAGEMENT

Spent fuel from nuclear power plants contains, in addition to U-235 and U-238, isotopes of plutonium and other highly radioactive fission products. The spent fuel can be reprocessed to remove the uranium and plutonium. The waste remaining is prepared for storage preliminary to disposal. The uranium, still slightly enriched (0.84 to 0.94 percent

U-235), is shipped back to the enrichment plant for reenrichment. For each metric ton of uranium reprocessed, about 9 kg of plutonium are recovered and stored.

Because no fuel reprocessing facilities or services are currently available to nuclear power utilities in the United States, spent fuel is stored at power plant sites and at temporary storage facilities. The problem of permanent storage of nuclear wastes is a matter of national concern. The nuclear power industry creates essentially two categories of waste: high level and low level. High-level wastes include the intact fuel rod assemblies of the reactors and those radioactive wastes (fission products and actinides) not separated out when the usable fissile materials are recovered during reprocessing.

High-level wastes require long-term isolation from the biosphere because of their high radioactivity. The United States is considering geologic disposal of high-level wastes in mined repositories—an option chosen by other nuclear power countries such as France and West Germany. Other options under consideration by the United States include placement of wastes in deep ocean sediments, deep drill holes, or a mined cavity; ejection into space; and portioning of reprocessing waste with subsequent transmutation of heavy radionuclides and geologic disposal of fission products.[18]

Low-level wastes include power plant equipment that has been exposed to radioactivity—for example, ion exchangers for purifying water used in the reactor gather a lot of radioactive material. Such wastes are disposed of at land burial sites at Beatty, Nevada, and Richland, Washington. (Two other low-level waste disposal sites are closed, one is filled to its licensed capacity, and another is operated only on a limited scale.[19])

RESEARCH PROGRAMS

The lead U.S. agency in nuclear power R&D is DOE. About 75 percent of the DOE-sponsored programs supports various aspects of nuclear fission research (such as fuel cycles and enrichment), and about 25 percent supports fusion research. A major part of the fission R&D program focuses on breeder technology. In support of LMFBRs, DOE is completing a 400 MWt research LMFBR—the Fast Flux Test Facility (FFTF)—at the Hanford Engineering Development Laboratory in Richland, Washington. The purpose of the FFTF is to test fuel elements and reactor components by providing a neutron environment similar to that anticipated in a fast breeder reactor. The Clinch River breeder reactor, an LMFBR, was to have been under construction for start-up in the early 1980s near Oak Ridge, Tennessee, but policy considerations (aimed at minimizing nuclear arms proliferation) have put this project on an inactive status, making its future questionable in the United States.

Research on the Advanced Water-Cooled Breeder Reactor (AWBR) is being conducted at Bettis Atomic Laboratory in Shippingport, Pennsylvania, supported by DOE. If successful, the AWBR could make it possible to convert the current class of light water reactors into breeder reactors. Another breeder concept under investigation is the gas-cooled, fast breeder reactor, which probably would operate on a U-235/plutonium fuel cycle.

The safety related Loss-of-Fluid Test (LOFT) facility operated by NRC at the Idaho

National Engineering Laboratory also is supported by DOE. Completed in 1978, LOFT has successfully demonstrated systems to provide emergency cooling to a reactor core, should a catastrophic event deprive the reactor core of its coolant. Additional tests are scheduled. Other efforts under the fission program focus on nuclear fuel cycle studies, including investigation into advanced fuel cycles, interim storage of spent fuel, reprocessing, and long-term storage and disposal of high-level nuclear wastes.

About two-thirds of DOE's fusion research budget is devoted to magnetic fusion, with the long-term goal of achieving electrical power generation. The general format of the program is to demonstrate the scientific and engineering feasibility of magnetic fusion by constructing a series of increasingly large experimental devices. Currently, the largest operating magnetic fusion device in the United States is the Princeton Large Torus (PLT), a tokamak facility that employs magnetic fields generated by superconducting magnets to confine heated plasma in a toroidal bottle. The plasma is heated by compression and by neutral beam injection. The PLT has reached temperatures of 60,000,000°K and has demonstrated plasma stability up to that temperature.

The next major step in magnetic fusion devices is the Tokamak Fusion Test Reactor currently under construction in Princeton. This reactor is expected to demonstrate scientific feasibility in the early 1980s by producing more energy in the form of heat than is consumed as electrical energy. As an alternative to the tokamak design, DOE also supports research on the magnetic confinement of plasmas by magnetic mirrors.

The DOE laser fusion program focuses on constructing a major laser fusion device (Nova) to be completed at Lawrence Livermore Laboratory in the early 1980s with an expected demonstration of scientific feasibility by the mid-1980s.

ECONOMICS

During 1977, the nuclear segment of the power industry generated an estimated 250 billion kWh, or 14 percent of national electrical consumption. Total costs of electric power for nuclear power plants are significantly lower than those for fossil fueled plants, although estimated investment or capital costs are higher. Nuclear and fossil fuel-fired plant costs are compared in some detail below.

Differences between average total costs for nuclear, oil and gas, and coal plants are presented in Table 7-8. The comparision between nuclear and oil- and gas-fired plants is particularly striking; the costs associated with oil and gas are over 2.5 times those of nuclear. Because of their low total costs, nuclear plants usually are chosen to carry base load, a

Table 7-8. 1977 POWER INDUSTRY PERFORMANCE

	Average Capacity Factor (Percent)	Average Availability Factor (Percent)	Average Total Cost (¢/kWh)
Nuclear	66.2	76.5	1.5
Oil/gas fired	50.3	78.9	3.9
Coal fired	57.1	76.8	2.0

Source: Atomic Industrial Forum, Info News Release No. 6, 20 April 1978.

fact that is reflected in the average capacities of the three types of plants. Capacity refers to the power produced as a percentage of that which would be produced if a plant were operating at full power, and on the average is lowest for oil and gas fueled plants, whose total costs are highest. Availability in Table 7-8 is the percentage of time (on the average) a plant is available for use, regardless of the level of operation.

Actual 1977 generation costs at the busbar (the cost of delivering energy to the transmission system at the generating station busbar) for the Commonwealth Edison Company's large coal and nuclear units are presented in Table 7-9. The total system includes, as well as the six large coal and nuclear units, 22 smaller coal- and oil-fired units and one smaller nuclear unit. Costs are divided into fuel, operation and maintenance, and carrying charges (depreciation, return on investment, property taxes, insurance, and income taxes). The coal burned was a combination of high-sulfur Illinois coal (at an average cost of 8.8 mill/kWh) and low-sulfur western coal (14.1 mill/kWh). Oil and natural gas costs (natural gas was occasionally substituted for coal in steam-electric units) averaged 29.6 mill/kWh and 22.7 mill/kWh, respectively.[20]

Comparisons of the cost components of nuclear and fossil-fired plants thus indicate that the total cost differences are caused primarily by differences in fuel costs. On the average, fuel costs for light water reactors and fast breeder reactors have been estimated at only 39 percent and 17 percent, respectively, of the fuel costs for coal-fired plants (1974 figures).[15] These percentages are expected to decrease over time, as coal mining and transportation are labor-intensive activities and thus very sensitive to increases in labor costs.

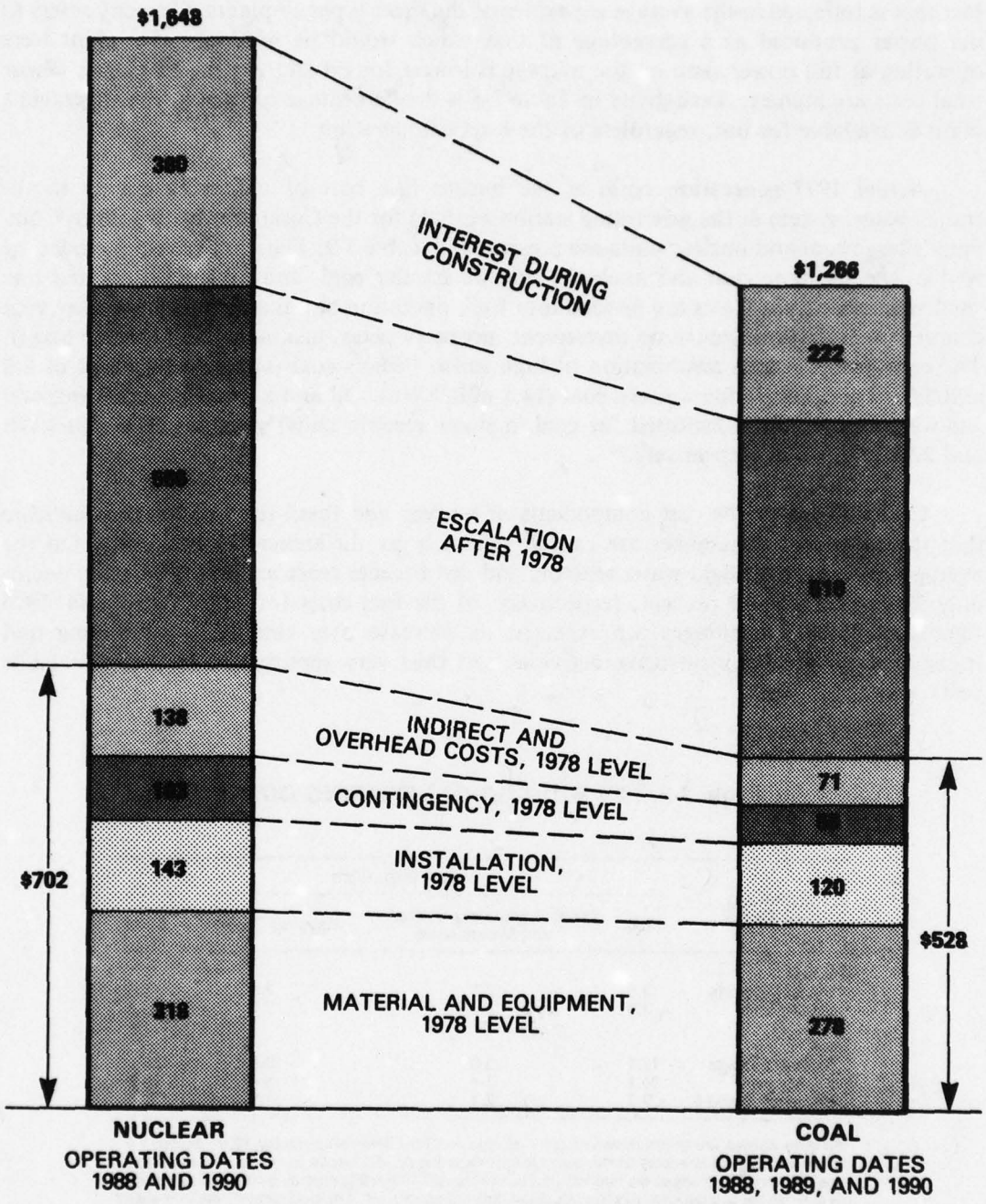
Table 7-9. 1977 BUSBAR GENERATING COSTS[a]

Generating Unit Group	Cost (mill/kWh)			
	Fuel	Other Production, Operation and Maintenance	Carrying Charges[b]	Total
Nuclear				
System average	3.5	2.2	7.6	13.3
Six big units	3.5	2.1	7.5	13.1
Coal				
System average	12.1	3.0	9.0	24.1
Six big units	10.1	2.4	8.4	20.9
Powerton 5 and 6	7.7	2.1	11.5	21.3

[a]All data shown are taken directly from Commonwealth Edison's books for 1977, except as follows: 1.3 mills is added to the nuclear fuel expense on the books to reflect the estimated cost of carrying charges on nuclear fuel in the reactor (0.8 mill), plus an additional allowance of 0.5 mill for the net cost of ultimate disposition of spent fuel. The data already include about 0.5 mill for spent fuel disposition. The coal fuel expense figures were increased by 0.6, 0.5, and 0.4 mill/kWh, respectively, to reflect the estimated carrying charges for maintaining a 90-day coal stockpile.

[b]Carrying charges were computed by applying a 20 percent annual fixed charge rate to the gross plant investment in the generating units in question and dividing by the number of kilowatt-hours generated (net) by such units in 1977.

Source: A. D. Rossin and T. A. Rieck, "Economics of Nuclear Power," *Science,* 18 August 1978.



Source: R. R. Bennett and D. J. Kettler, "Dramatic Changes in the Costs of Nuclear and Fossil-Fueled Plants " (New York: Ebasco Services, Inc., 1978).

Figure 7-4. PLANT COSTS/kW, 1978

The lower fuel costs more than offset the higher capital and operating cost for nuclear plants (resulting from the additional equipment and specialized personnel required). Over time, however, capital costs might escalate sufficiently to overrun the fuel cost differentials.

The average investment or capital cost today of two nuclear units going into service in 1988 and 1990 is estimated to be $1,648/kW, including $735/kW for escalation beyond 1978. A three-unit coal plant with service dates of 1988, 1989, and 1990 is expected to cost $1,266/kW, including escalation of $627/kW. Escalation includes cost increases due to inflation and additional statutory and regulatory requirements, and is estimated at 7 percent/year for both nuclear and coal-fired plants. Since 1969, inflation has increased investment costs for both types of plants by 100 percent, while the impact of statutory and regulatory requirements has been over three times that of inflation. Figure 7-4 shows the components of total investment costs for nuclear and coal-fired plants. Indirects and overheads include engineering, design, and related services; interest during construction is calculated at 8.5 percent/year. These values do not include costs such as land or land rights, the plant substation beyond the main power transformer, or any associated transmission to deliver the energy with the interconnected system.[21]

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8. HYDROELECTRIC POWER

Hydropower, or water power, is the oldest known mechanical power source. Hydropower supplies about 23 percent of the world's electricity and about 13 percent of the electricity produced in the United States. A renewable source, water power is essentially a product of solar energy. The sun evaporates water from land and sea; this moisture collects in the atmosphere to return later as rain or snow. Much of the water falls on high lands and drains into streams and large rivers as it flows back down to the sea. This flow can be harnessed by a hydroelectric plant to produce electricity. Useful power is generated when the water turns a wheel, or turbine. The greater the vertical distance through which the water falls (the head), the more useful it is in generating electricity, provided that a sufficiently large flow of water exists.

A conventional hydroelectric plant—one in which all of the power (electricity) is produced from natural streamflow as regulated by available reservoir storage—uses a dam to create a water storage reservoir and artificial waterways to harness the energy of falling water to produce electric power. Conventional hydroelectric plants can be used to provide base-load and, because they are capable of assuming load rapidly on demand, peak-load or emergency power. A base-load plant supplies power almost continuously to satisfy the minimum constant power demand in a system. For base-load power generation, the dam must either contain large amounts of water for reserve in times of drought, or be installed in a river with a large permanent flow. Several power plants may be required to furnish a system's base load. A peak-load plant generates power only during periods of peak demand, that is, when the power needed in a system exceeds that generated by the base-load plants. (Fossil fuel and nuclear power projects are difficult to shut down and to start up and, therefore, are not efficient peak-load plants.)

Hydroelectric plant operations are also the only practical way to store surplus electric power generated elsewhere (at fossil fuel or nuclear power plants) during off-peak hours. This is done by using the surplus electricity to pump water uphill for storage in the reservoirs. Later, when electricity is needed, the water can be released through the waterways to generate hydroelectric power. This pumped storage ability of hydroelectric plants is of particular value when the demand is cyclical. There are two major categories of pumped-storage projects: pure and combined. Pure developments produce power only from water that has previously been pumped to an upper reservoir, whereas combined developments utilize both pumped water and natural streamflow to produce power.

Hydropower is attractive because it can produce electricity without consuming irreplaceable fossil fuel and without producing waste products. Other advantages of hydroelectric power installations include the use of reservoir lakes for recreation, flood protection for downstream areas, and management of downstream flow to aid in water-quality control and to level out the extremes of winter versus summer stream conditions.

RESOURCE SUPPLY AND DEMAND

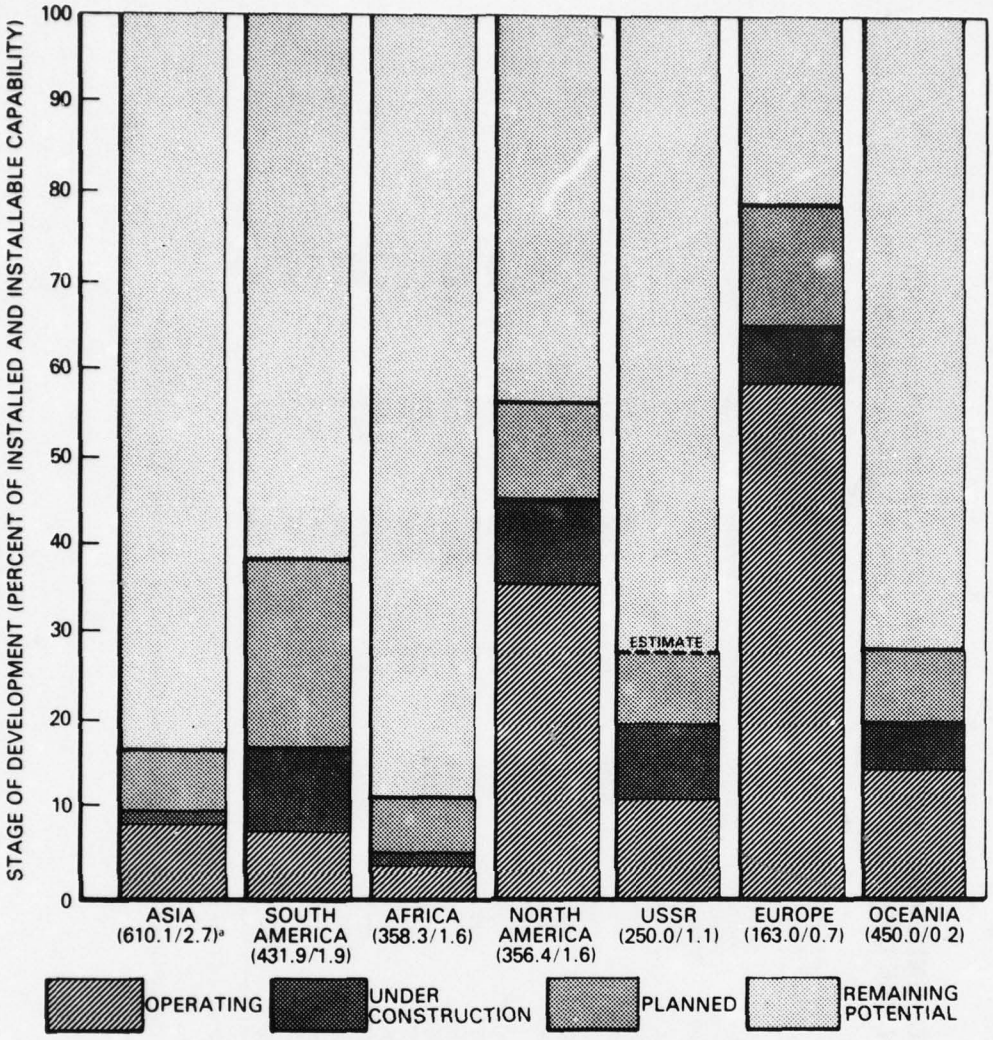
The potential world resource of conventional hydroelectric power, based on currently installed and economically installable plant capacities, totals 2,200 GW, with a potential annual energy production of 9.8 million GWh. (Producing the same amount of energy in an oil-fired thermal power station would require burning 14.6 billion bbl of oil a year, or 40 million bbl/day.) Of the total potential hydroelectric capacity, 28 percent is in Asia, 20 percent in South America, 16 percent in Africa, 16 percent in North America, 11 percent in the Soviet Union, 7 percent in Europe, and 2 percent in Oceania (see Figure 8-1).[1] Actual installed world hydroelectric generating capacity totals 372 GW (about 17 percent of the total potential capacity), with an annual production of 1.6 million GWh. In 1972, hydropower provided about 25 percent of the total world electric power production. In the same year, 74.5 percent of Canada's total electric power was generated by hydroelectric plants, whereas only 15.7 percent of the U.S. total was hydroelectric. The production figures of other countries are shown in Table 8-1.[2]

Table 8-1. HYDROELECTRIC CAPACITY OF NINE COUNTRIES, 1971-72

Country	Installed Capacity		Annual Production	
	MW	Percent of Nation's Total	Thousands of MWh	Percent of Nation's Total
United States	56,586	14.6	269,580	15.7
USSR	33,448	19.1	126,099	15.8
Canada	30,601	65.5	160,984	74.5
Japan	20,176	26.4	86,849	22.5
France	15,459	37.3	48,726	32.5
Italy	15,280	42.2	40,019	32.1
Spain	11,054	58.5	32,283	52.2
Federal Republic of Germany	4,842	8.9	14,054	5.4
United Kingdom	2,158	3.0	4,311	1.7

Source: Douglas M. Considine, ed., *Energy Technology Handbook* (New York: McGraw-Hill Book Company, 1977).

The potential U.S. resource of conventional hydroelectric power capacity totals 171,000 MW, with a potential annual energy production of 675 million MWh (Table 8-2). Figure 8-2 shows the developed and undeveloped hydroelectric potential in the United States by major drainage regions. (Undeveloped resources include areas of large hydroelectric potential where no dams have been built, and areas where dams have been built but where full generating capacity has not been fully exploited.) Of the major drainages, the Pacific northwest has the largest amount of both developed and undeveloped hydroelectric capacity, accounting for about one-third of the U.S. totals in each of these categories. Among the states, Washington has the largest developed capacity and the largest total developed and undeveloped potential. Alaska has the largest undeveloped potential. Of the potential U.S. resource, about 33 percent has been developed. As of 1976, developed conventional hydroelectric capacity in the United States totaled about 57,000 MW (compared to 11,000 MW in 1940), with an annual production of about 271 million MWh.



[a]Potential generating capacity (GW)/potential annual production (millions of GWh). World total potential generating capacity is about 2,200 GW at 50 percent capacity factor; total potential annual production is 9.8 million GWh.

Source: World Energy Conference, *World Energy Resources, 1985 2020* (New York: IPC Science and Technology Press, 1978).

Figure 8-1. POTENTIAL WORLD HYDROELECTRIC RESOURCES AND STAGE OF DEVELOPMENT, BY AREA

In addition to conventional hydroelectric power sources, there are, in many parts of the United States, sites offering physical opportunities for developing pumped-storage power. The inventory of this source is incomplete because there are many more sites than required for peaking needs for the foreseeable future. However, several hundred potential sites, located mostly in mountainous areas, have been identified and are capable of developing thousands of MW of capacity.[3] The total developed pumped-storage capacity in the United States as of 1 January 1976 amounted to 9,700 MW, including 7,300 MW in pure pumped-storage plants and 2,400 MW in combined plants. Pure pumped-storage plants with a total capacity of 2,700 MW and combined plants with a capacity of 1,600 MW were under construction. Table 8-3 summarizes the conventional and pumped-storage capacity developed

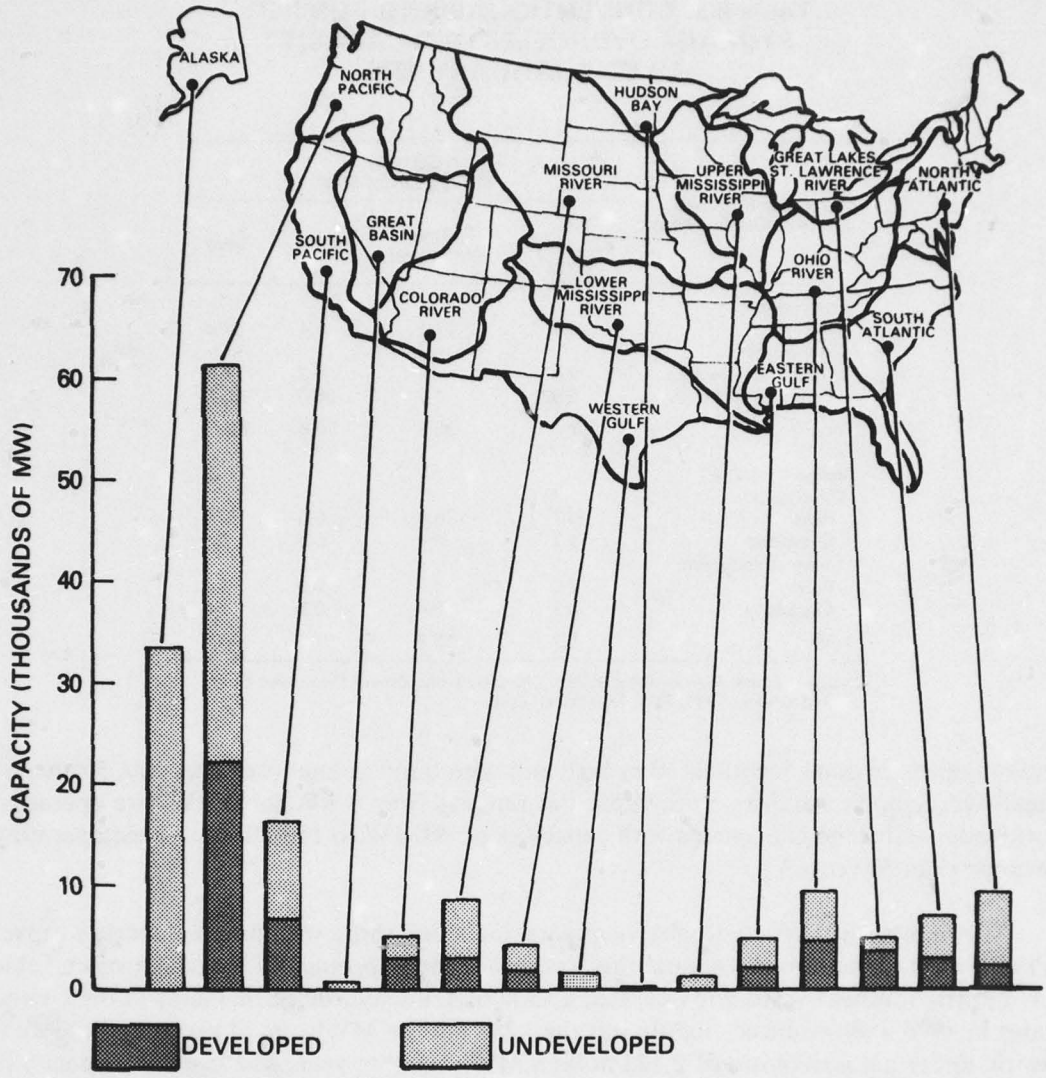
Table 8-2. DEVELOPED, UNDEVELOPED, AND TOTAL CONVENTIONAL HYDROELECTRIC POTENTIAL IN THE UNITED STATES, BY MAJOR DRAINAGE REGION, 1976

Region	Developed		Undeveloped		Total Potential		Percent Total Potential Capacity Now Developed
	Installed Capacity (MW)	Average Annual Generation (Millions of MWh)	Installed Capacity[a] (MW)	Average Annual Generation (Millions of MWh)	Installed Capacity[a] (MW)	Average Annual Generation (Millions of MWh)	
North Atlantic	2,712	10.9	7,132	18.3	9,844	29.2	27.6
South Atlantic	3,413	7.5	4,284	6.1	7,696	15.6	44.3
Eastern Gulf	2,371	7.2	2,733	4.0	5,104	11.2	45.4
Ohio	5,124	21.6	4,596	14.3	9,720	36.0	52.7
Great Lakes—St. Lawrence	4,008	24.8	1,304	3.8	5,312	28.5	75.4
Hudson Bay	14	0.1	0	0	4	0.1	100.0
Upper Mississippi	581	3.0	588	2.5	1,170	5.5	49.7
Missouri	3,370	15.3	5,486	19.0	8,855	34.3	38.1
Lower Mississippi	2,045	5.4	2,168	4.4	4,212	9.9	48.5
Western Gulf	458	1.3	1,261	2.3	1,719	3.6	26.7
Colorado	3,206	12.2	2,052	8.6	5,259	20.8	61.0
Great Basin	353	1.3	425	0.9	778	2.3	45.3
North Pacific	22,342	127.2	38,920	113.6	61,263	240.7	36.5
South Pacific	6,897	32.8	9,423	28.0	16,320	60.8	42.3
Alaska	123	0.5	33,283	175.8	33,406	176.3	0.4
Hawaii	18	0.1	35	0.2	53	0.3	34.2
Total United States[b]	57,035	271.1	113,690	404.0	170,725	675.1	33.4

[a]Includes potential capacity additions or subtractions at existing plants.

[b]Total may not add due to rounding.

Source: Federal Power Commission, "Hydroelectric Power Resources of the United States," FPC-P43, November 1976.



Note: The potential of Hawaii, amounting to 53 MW of which 18 are developed, is not shown.

Source: Federal Power Commission, "Hydroelectric Power Resources of the United States," FPC-P43, November 1976.

Figure 8-2. DEVELOPED AND UNDEVELOPED CONVENTIONAL HYDROELECTRIC POTENTIAL BY MAJOR DRAINAGE REGION, 1976

and under construction (as of 1 January 1976) by stage of development and type of authorization.[3]

Small low-head hydroelectric power is another energy resource that is underutilized. Development of small resources, including rehabilitation of abandoned hydropower sites and generation of power at dams that were constructed for nonpower purposes, could add 20,000 MW to the U.S. hydroelectric power capacity. Low-head hydroelectric projects

Table 8-3. CONVENTIONAL AND PUMPED STORAGE HYDROELECTRIC CAPACITY AS OF 1 JANUARY 1976

Type of Plant and Stage of Development	Capacity (Thousands of MW)			
	FPC Licensed Plants	Federally Authorized	Other	Total
Conventional				
Developed	26.5	27.1	3.4	57.0
Undeveloped				
Under consturction	0.8	7.2	0.2	8.2
Future potential	5.9	4.6	95.0	105.5
Total	33.2	38.9	98.6	170.7
Pumped storage				
Developed				
Pure	6.7	0.6	0.0	7.3
Combined	1.7	0.1	0.6	2.4
Under construction				
Pure	1.0	1.7	0.0	2.7
Combined	0.3	0.4	0.9	1.6
Total	9.7	2.8	1.5	14.0

Source: Federal Power Commission, "Hydroelectric Power Resources of the United States," FPC-P43, November 1976.

generally include dams less than 30 m high and with impoundments of less than 500 acres. Small hydroelectric facilities, with capacities ranging from 1 kW to 15 kW, are operating worldwide, and some U.S. plants with capacities of 100 kW to 15 MW have been operating for more than 50 years.[4,5]

The number of U.S. hydroelectric plants, including those with pumped storage capacity, and their capacities and annual production for 1966 through 1976 are shown in Table 8-4. Electric utilities owned and operated a total of 1,149 hydroelectric plants in the United States in 1976 and produced slightly less than 284 million MWh, or 13 percent of the total electric utility net generation of 2,123 million MWh for that year. The installed capacity in 1976 for these conventional and pumped storage hydroelectric plants was slightly less than 68,000 MW, about 12 percent of the total electrical utilities generating capacity of 557,000 MW. As shown in Table 8-4, the total number of hydroelectric plants has decreased since 1966 as older, small, and generally less efficient plants have been taken out of service in greater numbers than new installations have been constructed. However, installed capacity has increased 51 percent during that period, while net generation has increased 46 percent.[6]

Increases in the demand for electricity undoubtedly will result in continued investment in hydroelectric generating facilities. Given its large undeveloped resource, the United States could double its conventional hydroelectric generation capacity within 20 years without developing new technology.[4] Although the remaining undeveloped conventional sites have been characterized by decreasing economic justification and increasing environmental problems, many of these sites are becoming more attractive for development due to recent fuel shortages, increases in fuel prices, and increased costs of power from alternative sources.[6]

Table 8-4. HYDROELECTRIC PLANTS IN THE UNITED STATES, 1966-1976[a]

Plants	1966	1970	1971	1972	1973	1974	1975	1976	Percent Change 1966-1976
Federal									
TVA									
Number of plants	29	29	29	30	29	29	29	29	–
Installed capacity (MW)	3,076	3,119	3,143	3,195	3,205	3,205	3,212	3,231	5.0
Net generation (millions of MWh)	11.9	12.4	12.7	15.9	17.1	17.2	17.2	14.6	22.7
Bureau of Reclamation									
Number of plants	48	49	50	50	50	50	50	50	4.2
Installed capacity (MW)	6,923	7,494	7,605	7,651	7,801	7,835	8,512	9,690	40.0
Net generation (millions of MWh)	31.2	35.8	36.0	35.9	36.9	39.0	39.1	40.2	28.8
Corps of Engineers									
Number of plants	45	55	55	56	59	60	62	65	44.4
Installed capacity (MW)	9,490	12,302	13,020	13,212	14,950	14,536	15,641	15,962	68.2
Net generation (millions of MWh)	42.9	61.1	70.9	73.7	71.1	76.8	85.5	86.2	100.1
Other[b]									
Number of plants	8	8	8	8	8	8	8	8	–
Installed capacity (MW)	49	49	49	49	49	49	49	49	–
Net generation (millions of MWh)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	–
Private									
Number of plants	800	763	756	755	737	733	734	732	-8.5
Installed capacity (MW)	16,360	18,854	19,055	19,281	21,770	22,826	23,162	23,208	41.9
Net generation (millions of MWH)	62.8	70.5	78.4	78.7	76.6	87.7	80.3	71.1	13.2
Municipal, State, District, and Coops									
Number of plants	270	281	278	277	276	272	273	265	-3.7
Installed capacity (MW)	9,030	12,706	13,026	13,178	14,007	15,138	15,348	15,589	72.6
Net generation (millions of MWh)	45.5	66.1	68.2	68.4	70.8	79.6	77.8	71.5	57.1
Total									
Number of plants	1,200	1,185	1,176	1,176	1,159	1,158	1,156	1,149	-4.2
Installed capacity (MW)	44,928	54,524	55,898	56,566	61,782	63,589	65,924	67,729	50.7
Net generation (millions of MWh)	194.4	246.0	266.3	272.7	271.6	300.4	300.0	283.7	45.9

[a]Includes plants with pumped-storage capacity.

[b]International Boundary and Water Commission, National Park Service, and Bureau of Indian Affairs.

Source: U.S. Department of Energy, "Hydroelectric Plant Construction Cost and Annual Production Expenses 1976," DOE/EIA-0006/20, May 1978.

CONVENTIONAL HYDROELECTRIC PLANTS

Hydroelectric power is generated by using water under pressure to turn a wheel. A water-diverting structure, such as a dam or canal, impounds large quantities of water above a generating plant. Water is transported via large intake conduits to the turbines. Here the force of the water hitting the turbine blades causes them to spin, thus converting pressure energy into kinetic energy of the rotating shaft. The shaft drives an electric generator to produce electrical energy, which is carried by transmission lines to distribution centers. The amount of electricity produced is related directly to the amount of water and the available head (that is, the height of the water level above the turbine).

Generally, hydropower sites are developed to use all of the normal stream flow, and invariably conservation of water and its efficient use are paramount features of the design and operation. (Failure to pay heed to these features may destroy the net operating profit. Because of this, the operating personnel must maintain continuous scrutiny of all natural factors that can affect the station operation.) Conventional hydroelectric power plants can be classified as either run-of-river or storage plants. A run-of-river plant uses the natural passing waterflow without altering the amount or intensity of flow to areas downstream. Because run-of-river plants have a limited storage capacity at best, they are suitable only for sites with sustained flow during dry seasons or sites downstream from storage plants that can regulate the flow. In general, run-of-river plants are cheaper than storage plants of equal capacity, but they have a seasonal variation of output proportional to the variation of stream flow. Storage plants can regulate the flow of water to run-of-river plants located downstream to produce the optimum output because they have reservoirs of sufficient size to permit carry-over storage from one season to another. The storage capacity allows downstream flow to be regulated assuring an adequate supply of water to customers at all times.

As shown in Figure 8-3, typical hydroelectric plant superstructure includes a one or more story electrical bay, or wing, where the switching equipment, offices, storerooms, and most of the auxiliary equipment are located and a large building that houses the turbines and generators. In most cases, a forebay, a surge tank, or a vertical shaft is provided to store the surge of water that occurs when the plant is shut down or when the power output is reduced, thus reducing water hammer. The forebay also serves as the initial supply of water for startup if the power station is distant from the water source, or when increasing power output while water in the canal or pipeline accelerates.[7]

An intake structure in front of the water conduit houses trash racks to keep debris from the turbines. It also contains gates or valves to stop the flow of water for conduit inspection and maintenance. The water conduit may be short or long, depending on the location of the powerhouse relative to the water source. Conduits made of steel are called penstocks, and generally, the steel-lined concrete water passages and tunnels are also called penstocks. The most common design for low-head installations is a concentrated-fall development where the powerhouse is located close to the water source. In a divided-fall design, water is carried to the powerhouse through canals or penstocks over a long distance. Ideally, with the divided-fall arrangement a high head can be made available regardless of the size of the dam, thus allowing the turbine to operate at peak efficiency at all times.[8]

Turbines and generators are the main items of equipment in hydroelectric power plants. The type and size of turbine used at a specific location depends on the available head. Generally, for any one turbine type, the higher the head, the smaller the turbine needed to furnish the same power. A project is described as "high head" or "low-head" depending on the difference in water levels just upstream and downstream of the plant. A low-head plant uses turbines with runners requiring large volumes of water, which necessitate voluminous water passages. Large-diameter generators are also required because of the low operational speeds. There are large and complex intake works as well as an extensive and, therefore, expensive substructure (see Figure 8-4). High-head plants are generally located at some distance from the dam. Small volumes of water at high pressure turn the turbines at a high speed, allowing for a smaller generator diameter (see Figure 8-5).

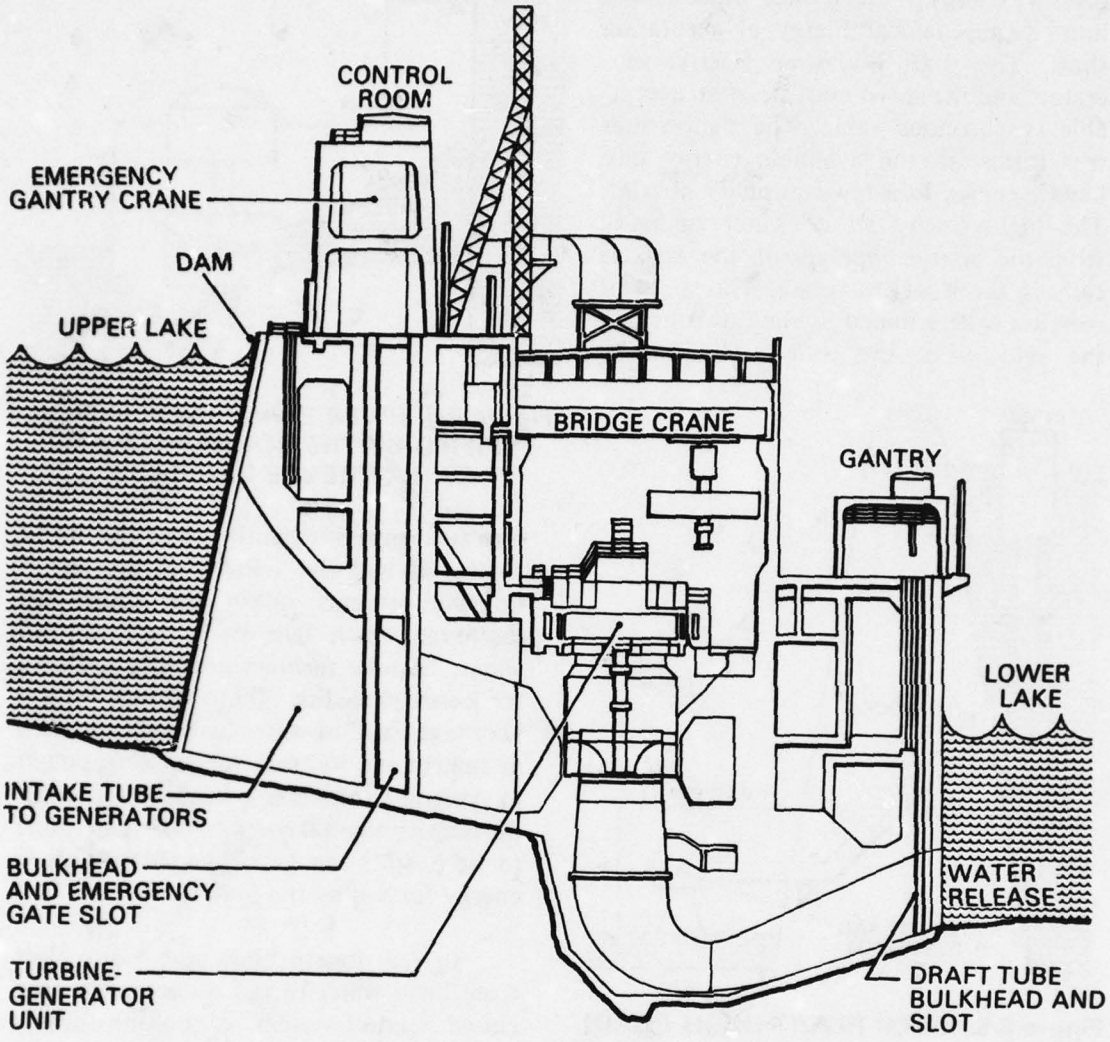


Figure 8-3. TYPICAL HYDROELECTRIC POWER PLANT

A hydraulic turbine suffers loss of efficiency at heads above or below the designed value because of shock losses. At the correct head, there will be one point of best efficiency, somewhere between 80 and 95 percent of full load. When a number of units are installed in a plant, and when steam reserve is available, it is possible to operate the units near the point of best efficiency. There are four operation and maintenance faults that can reduce the maximum energy production of a hydro plant: waste of water over spillways; improper distribution of the load between the station units; water leakage through valves, gates, dam, or flow line; and wear on moving parts, especially corrosion or erosion of the runner. The relative simplicity of hydroelectric equipment makes hydraulic efficiency of the turbine the prime consideration.[2]

There are two basic types of turbines: impulse turbines and reaction turbines. The impulse turbine, the most common of which is the Pelton wheel (see Figure 8-6), converts the

pressure energy of an elevated water supply into the mechanical energy of a rotating shaft. The shaft drives an electric generator, and the speed must be of an acceptable synchronous value. The Pelton unit transforms all the available energy into kinetic energy in a few stationary nozzles. The high-velocity jet of water emerging from the nozzle impinges on the buckets causing the wheel to rotate. The speed of rotation is determined by the flow rate and the velocity of the water. The turbine

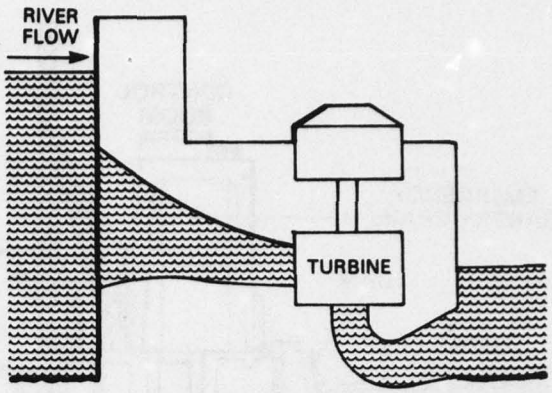


Figure 8-4. RIVER PLANT (LOW HEAD), TYPIFIED BY THE BONNEVILLE AND ST. LAWRENCE PROJECTS

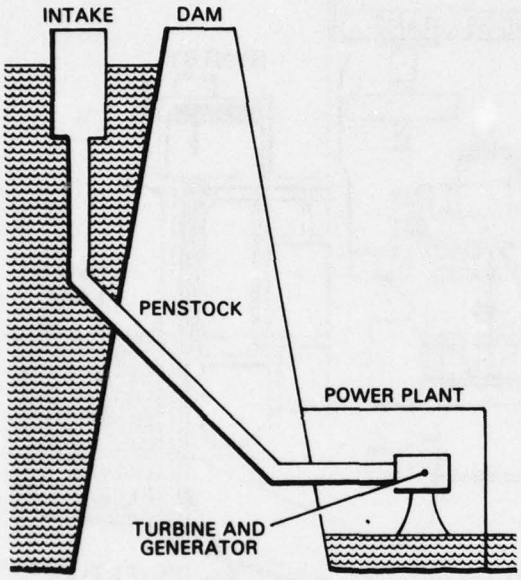


Figure 8-5. RIVER PLANT (HIGH HEAD), TYPIFIED BY THE HOOVER DAM AND NIAGARA INSTALLATIONS

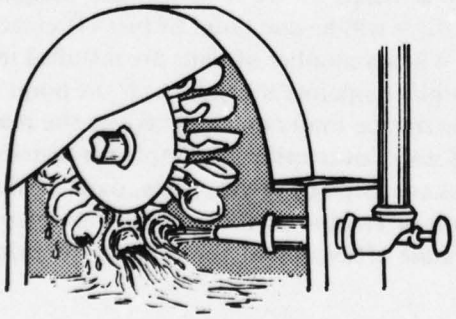
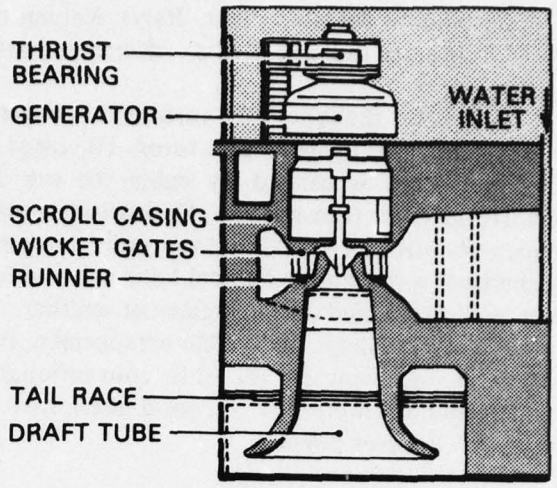


Figure 8-6. PELTON WHEEL

operates most efficiently when the wheel rotates at half the velocity of the jet. A housing prevents splash and guides the discharge which falls freely into the tail water. Impulse turbines generally are used for heads exceeding 300 to 400 m. With a very high head of water (over 400 m), such as that of the Reisseck hydroelectric plant in Austria (which has a head of 1,760 m), the entire potential energy of the water (due to its height) can be converted to kinetic energy for use by the impulse turbine.

In reaction turbines, the entire flow from head water to tail water occurs in a closed conduit system. A reaction turbine converts only part of the available head to kinetic energy in the nozzles at the entrance to the runner; a substantial part of the available head remains as pressure head, which varies throughout the turbine. The reaction turbine is distinguished from the impulse turbine by having moving nozzles (on the rotor) to convert pressure into velocity in the blade rings of the rotor as well as in the stationary nozzles. Reaction turbines generally use vertical shafts for better accommodation of the draft tube, a diverging discharge passage connecting the runner with the tailrace. Reaction turbines are represented by two types:

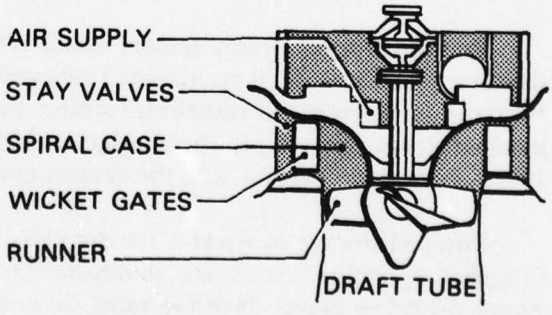
- Francis turbine. Francis turbines (see Figure 8-7) are submerged, with a draft tube and a continuous column of water from headrace to tailrace. The Francis turbine has fixed blades and operates at 12 to 120 rpm. There is some fluid acceleration in a continuous ring of stationary nozzles and further acceleration in the moving nozzles of the runner. In the Francis turbine, flow passes from the penstock to a spiral case and then inwardly around the inside circumference through a series of pivoting gates (wicket gates) to the runner, which resembles the blade arrangement in a jet airplane engine. Water flows through the curved runner vanes causing the runner to rotate. The vanes also deflect the water to the tailrace. The wicket gates control the flow of water and hence the power output. Francis reaction turbines are best used with moderately high heads of water (30 to 400 m), and have been applied for heads up to 672 m (Rosshag power station, Austria). The John Day Dam (one of the largest hydroelectric power projects in the world), located on the Columbia River in Washington, uses 16 Francis turbine-generator units to produce 2,200 MW. Four additional Francis turbine-generator units are planned for full capacity, adding 500 MW to the dam's present production.



Source: *Encyclopedia of Energy* (New York: McGraw-Hill Book Company, 1976).

Figure 8-7. FRANCIS TURBINE

- Vertical-flow propeller turbine. Propeller turbines are subdivided into fixed-blade and adjustable-blade (Kaplan) types. Diagonal-flow turbines also have been developed. In the propeller turbine, flow passes through wicket gates, but then is deflected downward onto the propeller blades and through the blades to the draft tube. The draft tube is shaped to decelerate the flow of water to the tailrace and at the same time accelerate the momentum of the turbine runner by converting the kinetic energy remaining in the discharge into suction head, thereby increasing the pressure difference on the runner. Low heads (under 30 m), such as those typically found in river plants or the La Rance tidal power plant (see Chapter 13), are best used by Kaplan reaction turbines (Figure 8-8) because these turbines operate at high speeds (over 100 rpm) to convert the pressure of the water into rotary motion. Propeller turbines have been applied for heads up to 88 m (Kaplan tur-



Source: *Encyclopedia of Energy* (New York: McGraw-Hill Book Company, 1976).

Figure 8-8. KAPLAN TURBINE

bines at Membia plant, Italy). Kaplan turbines are the basis of the immersed bulb turbines that are used as reversible pumps in pumped-storage installations.

Whatever the type, each turbine is connected to a generator by a common shaft; thus, the turbine turns the generator rotor. The rotor, passing through a magnetic field, generates electricity that is carried by cables to the control and switching apparatus, then to transformers for transmission. Hydroelectric plants where the generators are enclosed in one superstructure are called indoor powerhouses. Costs can be lowered by providing the generators with small individual housings (outdoor powerhouses). However, such units cannot be disassembled during inclement weather. Aboveground plants have the powerhouse at ground level. This is the typical arrangement of U.S. hydropower projects. However, it is often inconvenient to use this conventional design (as in a narrow gorge) and an underground powerhouse is a good alternative. Underground powerhouses are constructed in rock whenever possible.

PUMPED-STORAGE PLANTS

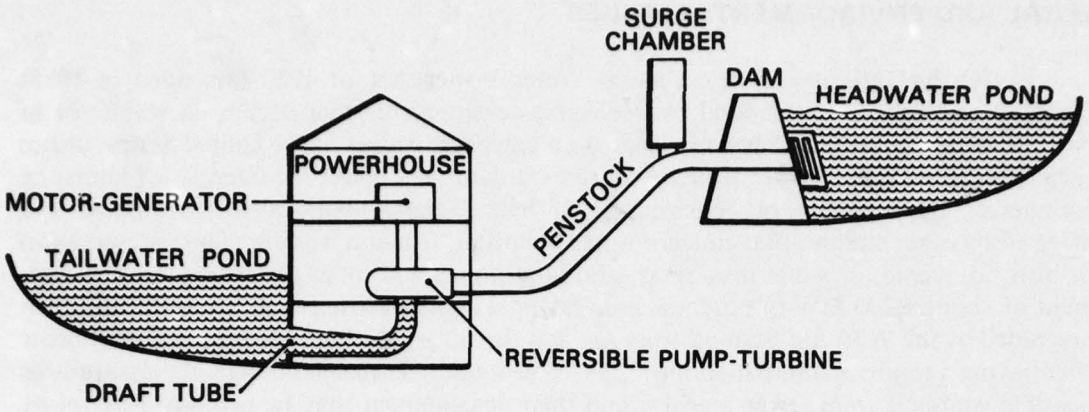
Pumped-storage projects are designed to provide peaking power. Planning and construction of pumped storage projects has increased because conventional hydroelectric sites capable of providing large amounts of peaking capacity are relatively scarce in many parts of this country, and because of the economies made possible by developing reversible equipment that can be used for both pumping and generating. To make power available from a pumped-storage plant during periods of high demand, water is pumped, using surplus power generated by base-load plants, to an upper reservoir during off-peak hours. This water is then released as required to provide the energy necessary to turn the turbines.

Pumped-storage installations are of two general types. One type uses both pumped water and natural run-off for generation, and the other exclusively uses pumped storage and generates power by recirculating the water between a lower and an upper reservoir. Of the 28 pumped-storage projects existing in the United States as of January 1977, 10 were of the recirculating, or pure, type. Examples of such plants are the Kinzua or Seneca projects on the Allegheny River in western Pennsylvania, Muddy Run on the lower Susquehanna River in south-central Pennsylvania, and Luddington on the eastern shore of Lake Michigan.

Pumped-storage plants require small reservoirs supplied by relatively little rainfall (because the same water is recirculated repeatedly) and reversible equipment (see Figure 8-9). With the development of reversible turbines that can be used as pumps, the total developed pumped storage capacity in the contiguous United States increased to about 11,200 MW in 1977, of which 80 percent is in the central and eastern states.

Pumped-storage projects often are classified with respect to the operating cycle. The principal operating cycles are daily, weekly, seasonal, or some combination thereof. Pumped-storage plants have the same favorable operating characteristics as conventional hydroelectric plants—rapid start-up and loading, long life, and low outage rates.

Usually, it is more economical to develop pumped-storage projects at high-head sites.



Source: R. K. Linsley and J. B. Franzini, "Hydroelectric Power," *Water Resource Engineering* (New York: McGraw-Hill Book Company, 1972).

Figure 8-9. SECTION THROUGH A TYPICAL PUMPED-STORAGE HYDROELECTRIC PLANT

The highest head of any existing pumped-storage development in the United States is 365 m at the Cabin Creek project in Colorado. The Montezuma project in Arizona and the Helms project in California will use heads of 490 m or more. There are indications that reversible units can be developed for heads of at least 600 m. Factors that contribute to the economic attractiveness of pumped-storage developments are the relatively low investment costs required and the increase in plant capacity of the thermal units which provide pumping energy during off-peak hours. Costs of development depend largely upon topographic, hydrologic, and geological conditions at the site.

RESEARCH AND DEVELOPMENT

U.S. R&D programs related to hydroelectric power generation are directed at utilizing the available small low-head resource on a cost-effective basis. Present use is limited to sites where the head is 9 m or higher, but an estimated 20,000 MW could be generated if lower heads could be used. The U.S. Department of Energy (DOE) plans to support methods of testing the technical and economic feasibility of low-head hydropower; as many as six demonstration plants may be funded (to a maximum of 25 percent of the cost of each project).[5] The total cost to DOE of this support of the commercialization of low-head hydropower will be $8.4 million.

DOE also is trying to stimulate manufacturers to produce off-the-shelf systems of less than 15 MW capacity for the use of small hydropower resources. In December 1978, the Federal Energy Regulatory Commission (FERC) issued a license for a proposed 14.8 MW hydroelectric plant on the Merrimack River in Massachusetts.[9] The electricity generated by the plant will be sold to the New England Power Company.

LEGAL AND ENVIRONMENTAL ISSUES

FERC, by authority of the Federal Water Power Act of 1920 (amended in 1935) regulates and licenses nonfederal hydroelectric developments that occupy in whole, or in part, lands of the United States; are located on navigable waters of the United States; utilize surplus water or water power from a government dam; and affect the interests of interstate commerce. Development or construction of hydroelectric plants also is regulated and affected by other statutes that concern water pollution; fish and wildlife plans; preservation of historic, scenic, or wilderness areas; and land policy and management issues. Development of about 9,200 MW of potential conventional hydroelectric capacity has already been precluded by the Wild and Scenic Rivers Act and similar legislation. Also, a number of other sites having a total potential of about 11,200 MW are in river reaches designated for study as possible wild and scenic river reaches, and their development may be precluded by future legislation. The U.S. Department of the Interior recently advised FERC that plants could not be licensed in any region under study for inclusion as a wild and scenic river.[3,10]

Environmental issues associated with hydroelectric power generation include the loss of habitats both upstream and downstream; the prevention of upstream spawning by several marine species, such as salmon; and, when spillways are used, the addition of nitrogen to the water. (Hydroelectric plants do not create air pollution, radioactive waste materials, or the thermal effects associated with nuclear or conventional power plants.) Land drowned when a dam is built may include valuable farmland or timberland, mineral deposits, or a village or small town. Substantial legal precedents exist to ease the process of condemnation and reimbursement, but the social effects of this loss on a rural community can be severe. To allow migrating fish to continue their accustomed spawning paths from the upper rivers to the sea and back again, many dams are now equipped with fishways. The John Day Dam, for example, has fish ladders on each side of the dam. Underwater vertical slots in each weir of the fish ladders enable fish to negotiate the rise without jumping, using the still pools for resting. The nitrogen problem will be eliminated as existing hydroelectric plants are expanded to their full capacities; turbine-generator units will take the place of nonproductive spillways. Water used to produce electrical power is unchanged after it flows out of the powerhouse into the river proper. Nothing is removed and no nitrogen is added. Generally, then, the environmental consequences of building a dam can be avoided by careful site selection, or mitigated through knowledgeable planning and management of the project.[11]

ECONOMICS

Total annual hydropower production (operation and maintenance) expenses in 1976 (Table 8-5) ranged from 0.33 to 5.57 mill/net kWh, and averaged 0.94 mill/net kWh. About two-thirds of the production costs are for operations and one-third for maintenance. (The corresponding unit costs, stated in terms of the annual cost per kilowatt of capacity, ranged from $2.39 to $18.92.) Plant size is a major factor affecting system hydropower production expenses. Other factors are the type of operation (base load or peaking service), annual generation, age of equipment, number and size of units, head, and other conditions peculiar to individual plants and systems.[6]

Table 8-5. HYDROELECTRIC POWER PRODUCTION EXPENSES OF SELECTED SYSTEMS, 1976

Company or System (Alphabetical by States)	Number of Plants	Installed Capacity Nameplate (MW)	Net Generation (Millions of kWh)	Annual Production Expense				Hydraulic Production Plant Investment Year End ($1,000)	Annual Plant Factor (Percent)
				Mill/Net kWh			$/kW Nameplate Capacity		
				Operation	Maintenance	Total			
Nonfederal									
Alabama Power Company (Alabama)	14	1,342.3	4,129.3	0.52	0.64	1.16	3.59	294,837	35
City of Los Angeles, Dept. of Water and Power (California)	14	726.3	1,734.3	0.99	0.77	1.76	4.20	163,137	27
Pacific Gas and Electric Company (California)	65	2,916.8	8,112.3	1.09	0.53	1.62	4.50	690,953	32
Southern California Edison Company (California)	35	720.7	2,550.4	1.36	1.28	2.64	9.32	214,744	40
Georgia Power Company (Georgia)	18	433.1	1,884.2	1.10	0.88	1.98	8.63	78,710	50
Idaho Power Company (Idaho, Nevada, Oregon)	16	1,276.6	9,246.0	0.22	0.11	0.33	2.39	254,143	82
The Washington Water Power Company (Idaho, Nevada, Washington)	9	618.1	4,206.6	0.46	0.20	0.66	4.45	147,009	77
Central Main Power Company (Maine)	24	208.0	1,512.1	1.37	0.83	2.20	15.94	67,147	83
New England Power Company (Massachusetts, New Hampshire, Vermont)	16	1,051.5	2,134.5	0.87	0.84	1.71	3.47	217,175	23
Minnesota Power & Light Company (Minnesota)	9	106.2	361.0	2.96	2.61	5.57	18.92	25,558	39
The Montana Power Company (Montana, Idaho, Wyoming)	13	469.9	3,741.7	0.86	0.18	1.04	8.26	70,062	91
Niagara Mohawk Power Corporation (New York)	81	657.5	3,590.8	0.85	0.89	1.74	9.50	145,342	62
Power Authority of the State of New York (New York)	4	4,102.0	23,986.4	0.61	0.16	0.77	4.49	671,371	67
Duke Power Company (North Carolina, South Carolina)	29	1,617.9	2,649.3	1.17	0.59	1.76	2.88	261,841	19
Pacific Power and Light Company (Oregon, Washington, Wyoming)	34	862.5	4,071.8	0.51	0.34	0.85	3.99	220,533	54
Portland General Electric Company (Oregon)	8	534.5	2,536.8	0.93	0.30	1.23	5.81	138,631	54
P.U.D. #1 of Chelan County (Washington)	4	1,426.5	8,535.8	0.29	0.13	0.42	2.51	253,954	68
P.U.D. #2 of Grant County (Washington)	2	1,619.8	12,363.5	0.21	0.13	0.34	2.55	290,738	87
Puget Sound Power & Light Company (Washington)	6	296.9	1,336.9	0.73	0.74	1.47	6.65	78,549	51
City of Seattle, Dept. of Lighting (Washington)	6	1,196.0	7,066.8	0.30	0.25	0.55	3.27	248,081	67
Subtotal	407	22,183.1	105,750.5	0.60	0.34	0.94	4.49	4,532,515	54
Federal									
Tennessee Valley Authority (Tennessee, Alabama, Georgia, Kentucky, North Carolina)									
Multipurpose dams	21	2,985.9	13,259.6	0.31	0.22	0.53	2.35	442,413	51
Single purpose dams	8	245.3	1,347.2	0.77	0.58	1.35	7.40	72,628	62
Subtotal	29	3,231.2	14,606.7	0.35	0.26	0.61	2.74	565,041	51
Total	436	25,414.3	120,357.2	0.57	0.33	0.90	4.26	5,097,556	54

Note: This selected group of utilities is intended to be a representative geographical cross section of systems having a significant hydropower capacity and representing several classes of ownership, including private, municipal, public utility district, and federal.

Source: U.S. Department of Energy, "Hydroelectric Plant Construction Cost and Annual Production Expenses 1976," DOE/EIA-0006/20, May 1978.

The advantage of low production costs is somewhat offset by the high initial cost of construction. Reservoirs, dams, waterways, pump-turbine, and motor-generator equipment represent 70 to 75 percent of the total investment cost. The investment cost (in 1976 dollars) at three federal plants that went into operation in the early 1970s varied between $200 and $953/kW (these costs include a portion of the cost of joint-use facilities). Differences in investment cost reflect primarily the wide variations in type, size, and location of projects; cost of purchasing land and relocating highways, railroads, buildings and other investments; and, to a lesser extent, changes in labor, materials, engineering, and other factors in construction costs.[6]

Because the major cost in a hydroelectric scheme is the dam (complete with reservoirs, waterways, turbines, and generators), the most economical way to create additional capacity is to expand existing facilities. For example, the capacity of the Bureau of Reclamation project at Grand Coulee on the Columbia River is being expanded by rewinding the generators of 18 main units to increase capacity from 2,229 to 2,380 MW, by building a third plant consisting of six units with a total capacity of 3,946 MW, and by installing six pumped-storage units in the existing pumping plants to increase total capacity by 350 MW. Unit investment costs and annual operating expenses per kilowatt-hour for hydroelectric plants can also generally be decreased by installing larger units.[6]

When considering costs, hydroelectric plants compare favorably with thermal electric plants. Hydroelectric plant production expenses are much lower, principally because no fuel is required and other operating and maintenance costs are usually less (see Table 8-6). The investment cost per kilowatt is substantially higher for conventional hydroelectric plants than for thermal electric plants, but life expectancy is also much higher. The life expectancy of hydroelectric plants is 50 to 70 years, while that of thermal electric plants is only 30 to 40 years. Furthermore, with multiple-use reservoirs, hydroelectric power plants share the costs among items such as water supply for irrigation or municipal use, navigation, recreation, and wildlife enhancement.[6]

Table 8-6. 1971-76 PRODUCTION EXPENSES, STEAM-ELECTRIC VERSUS HYDROELECTRIC PLANTS (Mill/net kWh)

Year	Steam-Electric Plants[a]				Hydroelectric Plants[b]		
	Operation	Maintenance	Fuel	Total	Operation	Maintenance	Total
1976[c]	.89	1.07	12.81	14.77	.60	.34	.94
1975	.70	.90	10.79	12.39	.46	.31	.77
1974	.51	.73	8.76	10.00	.41	.30	.71
1973	.45	.61	4.85	5.91	.39	.25	.64
1972	.42	.57	4.06	5.05	.37	.24	.61
1971	.42	.52	3.77	4.71	.35	.21	.56

[a]Weighted average expenses, steam plant cost book.

[b]Selected systems, nonfederal hydroelectric plants.

[c]Preliminary.

Source: U.S. Department of Energy, "Hydroelectric Plant Construction Cost and Annual Production Expenses 1976," DOE/EIA-0006/20, May 1978.

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9. GEOTHERMAL ENERGY

Geothermal energy is stored heat energy generated in the earth's interior and available to man from heated rocks or water within the upper 10 km of the earth's crust. The heat escapes very slowly from the earth's core to the crust by conductive flow through solid rocks, by convective flow in circulating fluids, and by mass transfer of magma (molten rock generated from within the earth, termed lava when expelled at the earth's surface). Thermal gradient describes the rate at which temperature increased with depth below the earth's surface and is expressed as degress per unit of depth. Normally, the earth's heat is diffuse, the thermal gradient averaging about 25 °C/km. In many areas, though, geologic conditions have created local thermal gradients much higher than the average; these areas usually are associated with young volcanism, thin crust, or tectonic plate boundaries. The thermal reservoirs contain enough concentrated heat to make up a potential energy source. The geothermal regions of the world are shown in Figure 9-1.

TYPES OF GEOTHERMAL SYSTEMS

Geothermal resources are classified according to the mode of heat transfer and the temperature and pressure of the geothermal system. Three types of geothermal systems are hydrothermal convection systems, hot igneous systems, and conduction-dominated areas.

Hydrothermal Convection Systems

In hydrothermal convection systems (Figure 9-2), heat is transferred to the earth's surface from a deep igneous source (magma) by the circulation of vapor or water. Vapor-dominated systems (sometimes inappropriately called "dry-steam deposits"), in which pressure is controlled by vapor rather than liquid, produce saturated to slightly superheated steam containing little or no liquid water and noncondensable gases, such as carbon dioxide and hydrogen sulfide, in contents ranging from a few tenths of a percent to 5 percent or more. Temperatures in these systems can reach 250 °C, and the steam can be used directly in turbines to generate electricity. The most successful and widely used steam geothermal systems (which occur rarely) are in The Geysers field, California; Larderello, Italy; and Matsukawa, Japan.

In liquid-dominated systems, hot water transfers heat from deep sources to a geothermal reservoir at depths shallow enough to be trapped by drill holes. Most liquid-dominated systems occur at hot springs, although other types exist. Hot water systems are about 20 times more common than vapor systems and usually are found in areas of volcanic origin and high seismic activity, for example, in the western United States and along the mid-Atlantic Ridge. Their brine (dissolved salts) content varies widely. The U.S. Geological

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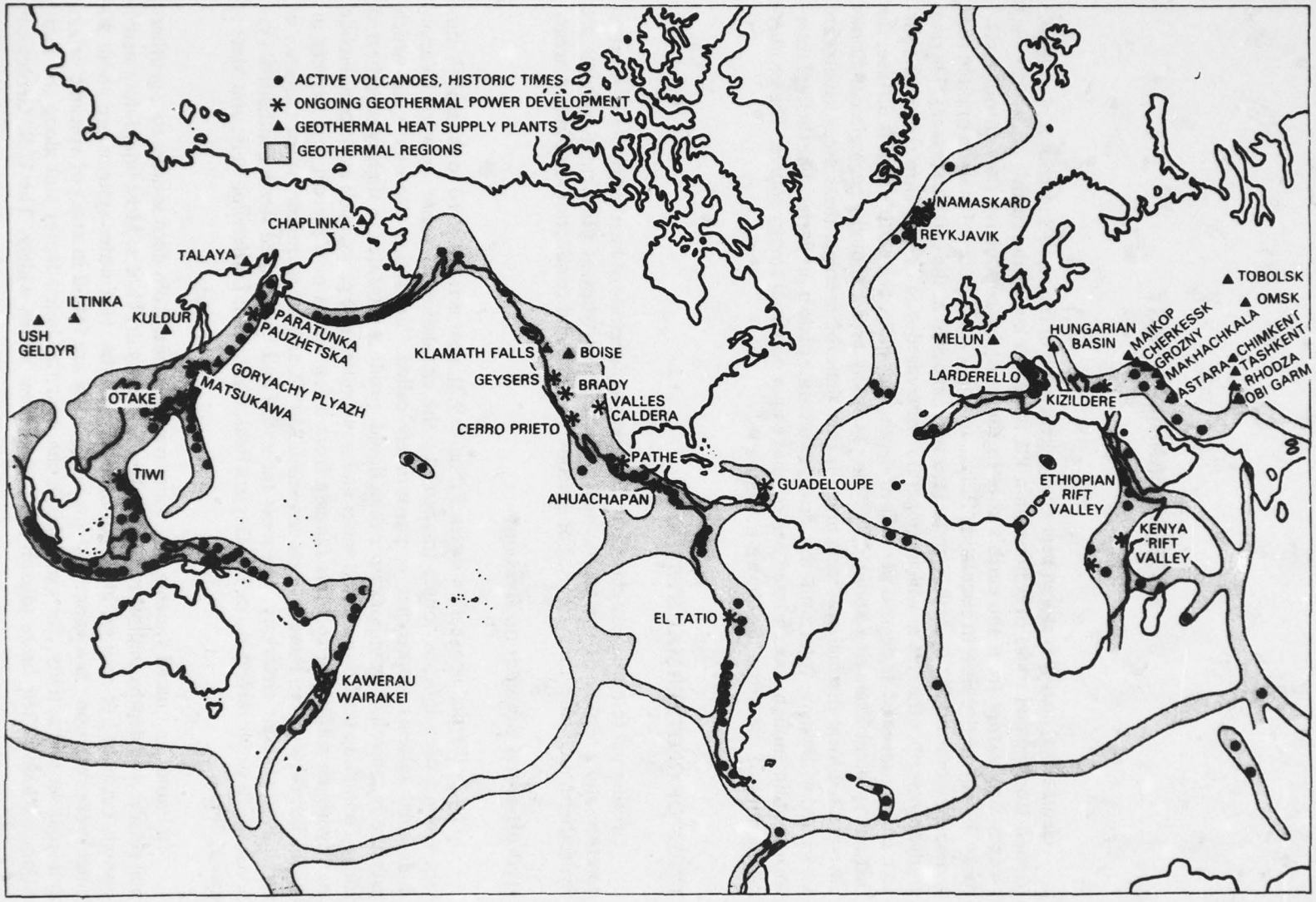
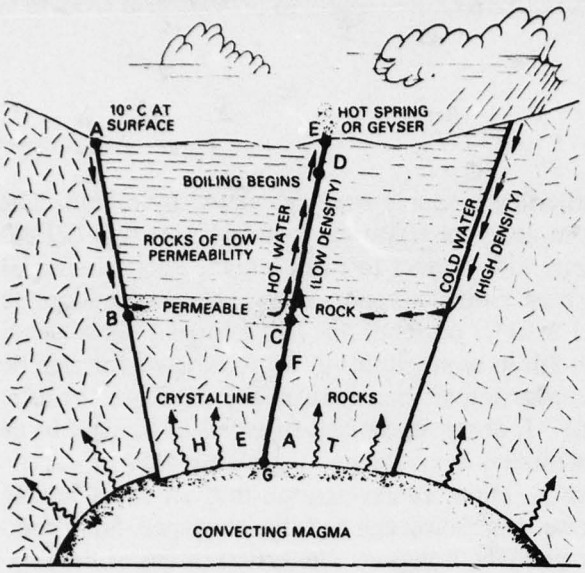


Figure 9-1. GEOTHERMAL REGIONS OF THE WORLD



Source: D. E. White, "Characteristics of Geothermal Resources," *Geothermal Energy* (Stanford University Press, 1973).

Figure 9-2. HYDROTHERMAL CONVECTION SYSTEM

Survey (USGS) has conducted substantial research on hydrothermal convection systems in the United States; details of the characteristics of hydrothermal, as well as other systems, can be found in numerous USGS publications.

Hot Igneous Systems

The rock formations in hot igneous systems are impermeable; thus no water is trapped in the system and the heat is transferred through the rocks. There are two major types of hot igneous systems: hot dry rock and magma. Hot dry rock, which exists because heat is transferred to the surrounding crust from bodies of magma, usually is found in depths of less than 6 km. Use of this resource depends on injection of water into the hot rock and return of heated water to the surface. Development is in the experimental stage.

Magma, or molten rock, systems underlie all the earth's crust, sometimes coming near the surface, or surfacing in the form of volcanoes. Recently, USGS estimated that the energy contained in molten and partially molten magma within 10 km of the surface in the United States is 50,000 quads.[1]

The potential resources in igneous systems are much greater than the hydrothermal potential, given technically and economically feasible methods of recovery.

Conduction-Dominated Systems

Geopressured deposits result when formation waters, covered by 2 to 3 km of impermeable clay beds, become highly pressured and hotter as they absorb heat rising from the earth's interior. Such areas are called geopressured zones and are worldwide phenomena. There is, for example, a large geopressured zone in the northeastern Gulf of Mexico beneath an area of over 278,500 km^2. The waters in such zones are characterized by abnormally high pressures and low salinities and in addition to their heat content, offer potential sources of energy for two reasons. The abnormally high fluid pressures may be a potential source of hydraulic energy, and the waters often are saturated with recoverable natural gas.

Normal thermal gradients (25°C/km) are areas of heat produced by heat flows, radiogenic production, and the thermal conductivity of rocks. The United States is studying

the potential of developing such areas in the eastern United States to provide heat from low-temperature reservoirs.

GEOTHERMAL RESOURCES

Table 9-1 shows the worldwide geothermal resource base calculated by region. The numbers shown are estimates derived from an Electric Power Research Institute (EPRI) analysis involving a number of assumptions with respect to heat content and volumes of thermal resources. (The sum of resource base estimates reported by individual nations in response to an EPRI questionnaire was 2.1×10^{24} J or about 5×10^{23} calories.)[2] Only about 2 percent of this resource base is high enough in temperature to be considered for electric power production. Overall recovery and conversion efficiencies also are small, yet the electric power potential is substantial: 1.8×10^{22} J, about 20 percent of which is thought to be producible by current technology. This potential is equivalent to 1.2 million MW of electric generating capacity operating for 100 years. These values assume that all areas having geothermal deposits suitable for electric power generation can be fully developed. Such complete development may not be practical or possible, however. The actual extent of development will depend on local conditions and regulations.[3]

Significant geothermal resources in the United States are located primarily in the western and Gulf Coast regions and include Alaska, Arizona, California, Colorado, Hawaii, Idaho, Louisiana, Nevada, New Mexico, Oregon, Texas, Utah, Washington, and Wyoming. In general, the average heat content of rocks is considerably higher in the western United States than in the east. Nearly all economically important geothermal resources are found west of the Rocky Mountains, in provinces of geologically young or present-day tectonism. Seven provinces are recognized as containing most geothermal resources in the western United States (see Figure 9-3). East of the Rocky Mountains, the northern Gulf of

Table 9-1. CALCULATED GEOTHERMAL RESOURCE BASE,[a] BY REGION AND TEMPERATURE CLASS

Region	Resource (Joules)				
	<100°C	100-150°C	150-250°C	>250°C	Total
North America	7.1×10^{24}	1.2×10^{24}	3.2×10^{23}	2.0×10^{22}	8.6×10^{24}
Central America	1.5×10^{23}	8.8×10^{22}	2.8×10^{22}	1.7×10^{21}	2.7×10^{23}
South America	4.6×10^{24}	8.3×10^{23}	2.3×10^{23}	1.4×10^{21}	5.7×10^{24}
Western Europe	1.5×10^{24}	7.1×10^{22}	1.9×10^{22}	1.2×10^{21}	1.6×10^{24}
Eastern Europe	6.7×10^{24}	2.5×10^{23}	6.3×10^{22}	4.0×10^{21}	7.0×10^{24}
Asia	7.5×10^{24}	7.9×10^{23}	2.1×10^{23}	1.3×10^{22}	8.5×10^{24}
Africa	5.2×10^{24}	3.3×10^{23}	7.0×10^{22}	9.4×10^{21}	5.6×10^{24}
Pacific Islands	3.3×10^{24}	2.6×10^{23}	1.7×10^{23}	1.0×10^{22}	3.7×10^{24}
Total	3.6×10^{25}	3.8×10^{24}	1.1×10^{24}	7.3×10^{22}	4.1×10^{25}

[a]The base underlying the continental land masses to a depth of 3 km and at temperatures above 15°C.

Sources: Electric Power Research Institute, "Geothermal Energy Prospects for the Next 50 Years," Preliminary Report to the World Energy Conference, ER-611-SR, February 1978, and World Energy Conference, *World Energy Resources 1985-2020* (IPC Science and Technology Press, 1978).



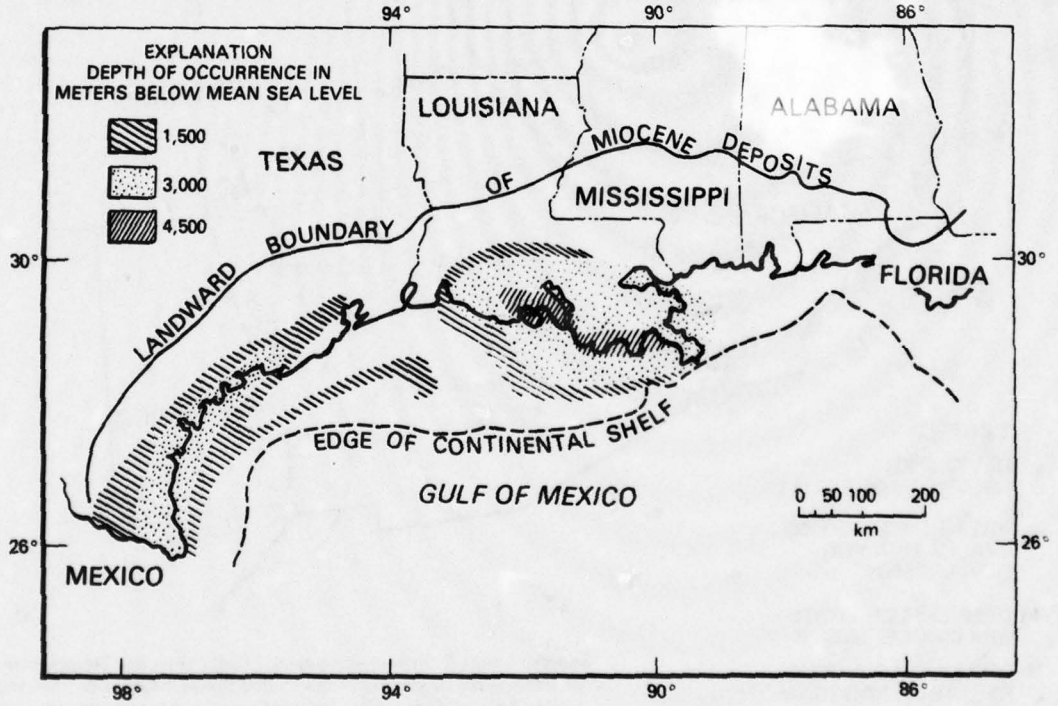
Source: James B. Koenig and others, "Exploration and Development of Geothermal Resources in the United States 1968-1975," Second United Nations Symposium for the Development and Utilization of Geothermal Resources, San Francisco, May 1975.

Figure 9-3. GEOTHERMAL EXPLORATION IN THE UNITED STATES

Mexico basin geopressured zone, shown in Figure 9-4, is the most significant geothermal resource area. Lower-temperature resources on the East Coast have been identified. Table 9-2 summarizes 1975 USGS estimates of heat content of the geothermal resource base of the United States with regard to the three types of geothermal systems.

Exploration for geothermal resources in the western United States increased rapidly from 1968 to 1976, encouraged by new public land leasing policies, increasing prices of energy, and the successful development of geothermal energy at The Geysers (see Figure 9-3). Significant discoveries were made in Imperial Valley, California, and Valles Caldera, New Mexico. Exploration has continued at Beowawe and Brady's Hot Springs, Nevada, and Surprise Valley, California. In addition, exploration accelerated in portions of Utah, Idaho, Oregon, and Arizona.[4]

In 1976, 1977, and 1978, resource exploration and assessment resulted in the identification of Roosevelt Hot Springs, Utah, and the Snake River Plain, Idaho, as being areas of much larger resource potential than previously identified.[5] Very hot fluids (360°C) at good flow rates were discovered in Hawaii. In Louisiana, the Department of Energy (DOE) has an active program to study the potential of the geopressured aquifers along the Gulf Coast. An abandoned natural gas production well was reopened to 3,930 m for an encouraging 3-week



Source: Paul H. Jones, "Geothermal Resources of the Northern Gulf of Mexico Basin," *Geothermics*, Special Issue, Part 1, 1970.

Figure 9-4. LOCATION AND DEPTH OF THE GEOPRESSURED ZONE, NORTHERN GULF OF MEXICO BASIN

Table 9-2. HEAT CONTENT ESTIMATES OF THE U.S. GEOTHERMAL RESOURCE BASE, 1975[a]

Type of System	Temperature Characteristics	Natural Fluid Supply	Number of Identified Systems	Heat Content (10^{18} Calories)	Identified and Estimated for Undiscovered Heat Content (10^{18} Calories)	Comments
1. Hydrothermal convection systems (relatively high temperatures at shallow depths; heat content estimated only to 3 km depth[b]						Relatively high favorability due to the fact that convection of water (or steam) transfers heat from hot, deep areas of system to near-surface areas. Thus, higher temperatures are attained in shallower wells at lower cost than normal temperature gradient areas, where heat transfer is predominantly by conduction through solid rock.
a. Vapor-dominated systems	~240°C	Available; not always adequate	3	26	50	1a and 1b include all areas that are presently being utilized or explored for generation of electricity.
b. Hot-water systems						
(1) High-temperature systems	150°C	Available; not always adequate	63	370	~1,600	
(2) Intermediate-temperature systems	90 to 150°C	Available; not always adequate	224	345	~1,400	Systems are attractive for nonelectrical space and process heating.
(3) Low-temperature systems[c]	<90°C	Available; not always adequate	–	–	–	Systems with maximum temperatures of 90°C are omitted due to lack of adequate data.
Total			290	~741	3,050	
2. Hot igneous systems (excluding hydrothermal convection systems above; heat content estimated from 0 to 10 km depth[d]					~100,000	Provides major challenges for future utilization.
a. Assumed part still molten	>650°C	Inadequate	48 best-known including Alaska and Hawaii	~13,000		Contains most stored heat per unit mass of volume. Technological problems of utilizing this heat are the most difficult of all systems listed.
b. Assumed hot molten but very hot ("hot dry rocks")	<650°C	Generally inadequate	Crystallized parts and hot margins of same	~12,000		May not always be as hot or dry at shallow and intermediate depths because hydrothermal convection in natural fractures may be more common than surface evidence indicates.
Total			48	25,000	~100,000	
3. Conduction-dominated areas (by heat-flow provinces, utilizing available data on heat flows, radiogenic heat production, and thermal conductivity of rocks; heat contents estimated for 0 to 3 km and 3 to 10 km depth). Category includes the Gulf Coast geopressured environment with its fluid fraction[e]	15 to 300°C	Adequate in parts of sedimentary basins, generally inadequate elsewhere	0 to 10 km; all 50 states subdivided into 19 heat-flow provinces of 3 basic types (Eastern, Basin and Range, and Sierra Nevada)	~8,000,000	~8,000,000	Volumes of rock involved are high, but average temperatures are low. Convection of natural fluids is a minor factor in many conduction-dominated areas. Geopressured environment of Gulf Coast is probably the most significant of conduction-dominated areas for development.

[a]Heat in the ground at temperatures above 15°C, to specified depths and without regard for recoverability.

[b]J. L. Renner, D. E. White, and D. L. Williams, "Hydrothermal Convection Systems," *Assessment of Geothermal Resources of the United States,* USGS Circular 726, 1975.

[c]U.S. Geological Survey, "Thermal Springs of the United States and Other Countries of the World—A Summary," Professional Paper 492, 1965.

[d]R. L. Smith and H. R. Shaw, "Igneous-Related Geothermal Systems," *Assessment of Geothermal Resources of the United States,* USGS Circular 726, 1975.

[e]S. S. Papadopulos and others, "Assessment of Onshore Geopressured—Geothermal Resources in the Northern Gulf of Mexico Basin," *Assessment of Geothermal Resources of the United States,* USGS Circular 726, 1975.

Note: Many assumptions are made in these estimates, particularly with regard to temperature and temperature distributions, geothermal reservoir characteristics/composition, and heat content and structure. Considerations of these assumptions is necessary when comparing estimates from different sources.

test. DOE expects to drill wells specifically designed for geopressured fluid production. There are three potential resources in the Gulf Coast aquifers: methane gas dissolved in the hot water, heat (minimum of 150°C) in the water, and the water itself (which could be desalinated for agricultural purposes).

Serious evaluation of geothermal resources in the eastern United States began in 1976. Scientists at Virginia Polytechnic Institute theorized that commercially exploitable reservoirs will occur where crustal radiogenic heat sources (usually in granites) are overlain by coastal plain sediments that retain the heat energy resulting from the radioactive decay. DOE is drilling wells in several eastern States to locate low-pressure fluids. However, the potential of this resource is relatively unproven, and application probably would be limited to nonelectric systems.

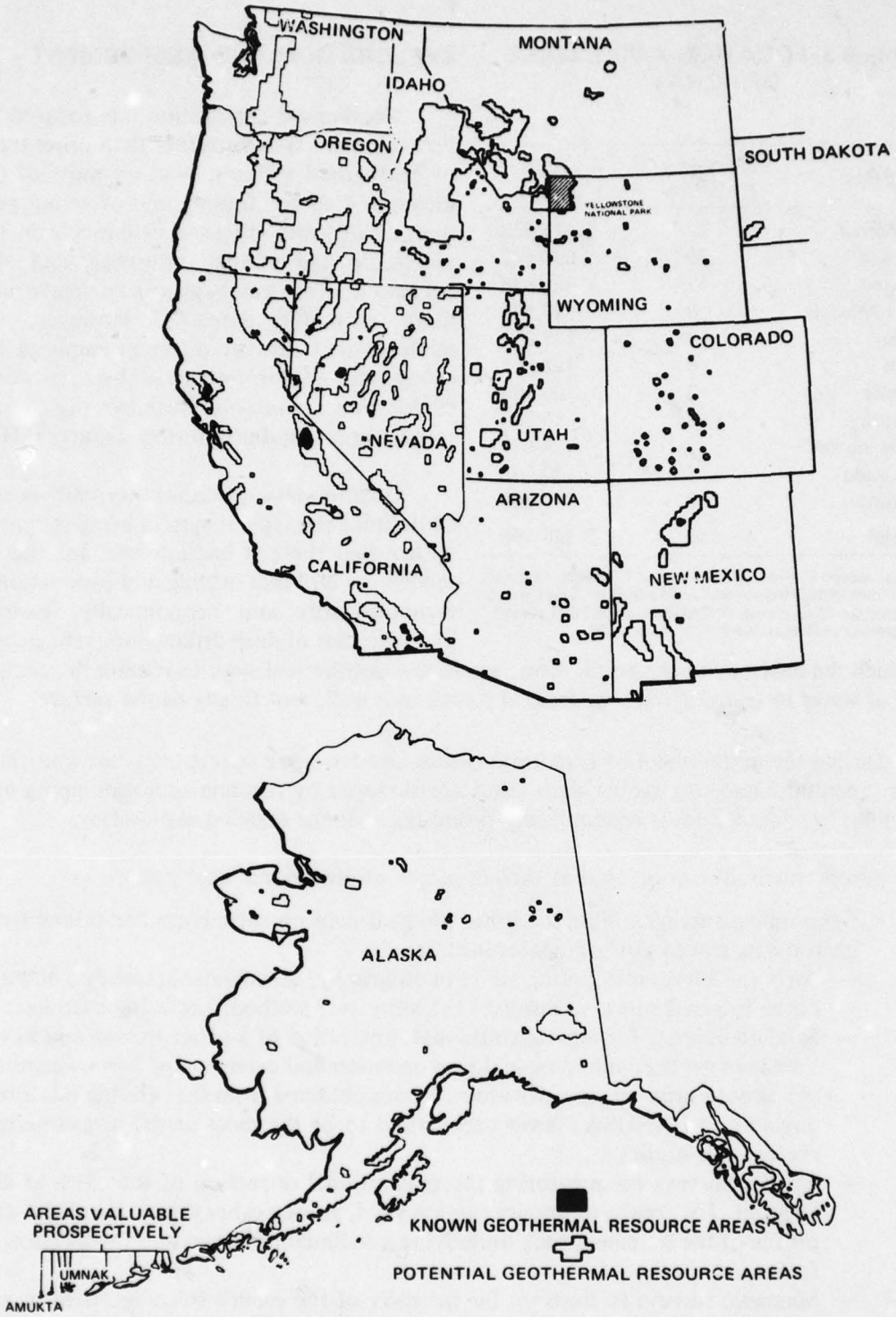
Several states have passed laws to permit leasing of state lands for geothermal exploration; however, the increased availability of land has coincided with increased legal requirements for environmental protection, resulting in conflicts and delays in the issuance of drilling permits, particularly in California. The problem of defining surface rights, mineral rights, and water rights to allow for geothermal exploration and drilling activities has not been resolved in some areas. (See "Legal and Institutional Problems" in this chapter.) Increased interest in the U.S. geothermal energy potential has encouraged both public and private sources to make financing more readily available for exploration and related activities.

As a result of exploration and commercial interest in geothermal development, known and potential geothermal resource areas in the United States, shown in Figure 9-5, have been identified. The Geothermal Steam Act of 1970, which authorizes the Secretary of Interior to issue leases for development and utilization of geothermal steam and related resources, defines a known geothermal resource area (KGRA) as an area in which the geology, nearby discoveries, competitive interests, or other indicia would, in the opinion of the Secretary (Interior), engender a belief in men who are experienced in the subject matter that the prospects for extraction of geothermal steam or associated geothermal resources are good enough to warrant expenditures of money for that purpose.

A KGRA can also be defined in terms of the minimum requirements necessary for economic development,[6] that is:

- Temperatures from 65 to 204°C, depending on production and use technology.
- Depths less than 3,048 m to permit economical drilling.
- Sufficient rock permeability to allow the heat transfer agent—water, steam, or both—to flow continuously at a high rate.
- Sufficient water recharge to maintain production over many years.

Any area established as a KGRA must be leased competitively. Table 9-3 shows the location and extent of currently established KGRAs.



Source: U.S. General Accounting Office, "Problems in Identifying, Developing and Using Geothermal Resources," 6 March 1975.

Figure 9-5. KNOWN AND POTENTIAL GEOTHERMAL RESOURCE AREAS IN THE UNITED STATES

Table 9-3. LOCATION AND EXTENT OF KGRAs

State	Number of KGRAs	Total Acres
California	23	1,424,603
Nevada	30	635,462
Oregon	13	431,936
New Mexico	8	327,853
Idaho	8	175,452
Utah	8	122,567
Alaska	3	88,160
Montana	4	58,655
Washington	3	34,612
Colorado	4	20,825
Arizona	2	3,700
Total	106	3,324,185

Source: Joseph P. Riva, Jr., and James E. Mielke, "Energy From Geothermal Resources," Committee on Science and Technology, U.S. House of Representatives, 2nd edition, Congressional Research Service, June 1978.

EXPLORATION AND ASSESSMENT

Geothermal exploration has focused on hydrothermal systems rather than other types of geothermal systems, because most of the methods used for finding and assessing geothermal deposits are used extensively in the petroleum and mining industries, and also because hydrothermal systems currently have more economic potential. However, the methods are used with different emphasis for geothermal exploration than for petroleum exploration, primarily because the occurrence, nature, and uses of the resource differ.

Geothermal exploration normally begins by defining the type of system being sought to ensure that there is enough heat for the intended use and that drilling and production is technologically and economically feasible. The high cost of deep drilling limits the depths at which the heat can be extracted. Also, productive geothermal systems require the circulation of water to transfer the heat from the rock to a well, and finally to the surface.

During the initial phase of exploration, sites and areas are selected that are known to have potential based on existing data. Sites are surveyed by reconnaissance mapping and sampling to select the most economically promising sites for detailed exploration.

Several methods can be used at various stages of geothermal exploration:

- *Geophysical surveys,* done to gather physical data on subsurface conditions from instruments placed at the surface, include:
  - — Airborne surveys, including aerial photography, aeromagnetic surveys, and airborne infrared surveys, although the latter two methods are being used less.
  - — Satellite imagery for initial geothermal exploration of a given area as well as for "detailed geologic mapping and interpretation and extension of known geothermal sites to other prospective areas." Data obtained from the orbiting platforms Skylab and LANDSAT have been found to be the most useful in geothermal exploration studies.[7]
  - — Gravity surveys for measuring the gravitational attraction of the earth at any location. The results of gravity surveys yield, among other things, the depth and profile of the basement rock underlying a sedimentary basin and the location of faults.
  - — Magnetic surveys to measure the intensity of the earth's magnetic field at any location. This survey provides results similar to the gravity survey.
  - — Passive and active seismic surveys to record naturally occurring microearthquakes or seismic ground noise. Microearthquakes are recurring low-intensity

earthquakes, usually not felt by humans, caused by fracturing and displacement of subsurface rock along an active fault. Such active faults often are considered to be the flow conduits of geothermal water from depth. Seismic ground noise implies continuous low-intensity vibrations in the subsurface and may be associated with geothermal areas. (Results of tests conducted recently using advanced seismic exploration technology, for example active seismic techniques, have been reported at several meetings, including the Geothermal Resources Council meetings in May 1977 and July 1978.)

- *Geologic and hydrologic surveys* include structural and stratigraphic mapping to locate recent faults, and to determine the age of young volcanic rocks and location of surface thermal manifestations. Hydrologic analysis includes temperature and discharge measurements of hot and cold springs, evaluation of surface and subsurface water movements, and collection of basic meteorologic data.
- *Geochemical surveys* involve using data obtained from chemical analysis of water and gas samples to determine whether the system is vapor- or liquid-dominated, estimate temperatures and chemistry of the waters at depth, and determine the source of recharge water. Analysis of the isotopic content can be used to specify the origin of the water in hydrothermal systems.
- *Heat flow studies* involve measurement of temperature gradients in shallow boreholes (30 to 150 m) drilled in an area considered prospective from other surveys. Knowing the thermal conductivity (K) of the subsurface rock, which is either measured from samples of the rock or assumed from experience, the rate of vertical conductive heat flow (q) can be calculated from Fourier's Law:

$$q = -K\frac{dT}{dz}$$

where dT/dz is the vertical temperature gradient. Geothermal areas exhibit heat flow rates of several times the worldwide average of 1.5 microcal/cm^2/s.

Surface and near-surface exploration techniques provide information that allows selection of sites for exploratory holes that can be drilled to 3 km deep. Tests such as sampling, well-logging, and heat flow analysis are conducted in these wells. They are the only methods used to determine actual geothermal-reservoir properties and to evaluate the potential for heat, power, minerals, or fresh water. (Data acquired from the drill holes ideally should include temperature-depth distribution, pressure-depth distribution, permeability, porosity, lithology and stratigraphy, and fluid composition.) A full set of geophysical logs combined with production tests will provide the necessary data and allow evaluation of the site.

Information that can be obtained only from a borehole is essential for estimating the ability of the geothermal reservoir to produce energy over a long enough time to be economically attractive, distinguishing between different models of the geothermal system, with the aim of accurately predicting production characteristics under varying exploitation conditions, and calibrating and refining geophysical and geochemical methods for recognizing and delimiting geothermal systems.

Current research in exploration technology focuses on developing equipment, particularly for borehole sampling and analyses, which will operate in the severe environment of geothermal systems. Ways to reduce costs are also of interest, since exploration and drilling constitute a major portion of geothermal development investment requirements.[8] For example, magnetotelluric techniques and automagnetotelluric techniques are being developed under DOE sponsorship. Geonomics, Inc., recently announced availability of a reliable magnetotelluric system that can produce electrical-resistivity soundings to great depths. Sandia Laboratories is developing an electronic geothermal well logging tool that will simultaneously read temperature, pressure, and flow. The new tool can operate at the high temperatures (to over 300°C) found in geothermal wells.[9]

DRILLING

Techniques used for drilling geothermal wells are similar to those used for conventional drilling for petroleum: rotary rigs efficient to 7.5 km and up to 250°C. The average well depth at The Geysers is 2.3 km, and wildcat wells elsewhere have gone as deep as 3.3 km. Few significant holes are drilled to less than 1.2 km.[4] However, there are some specific problems encountered in drilling geothermal reservoirs that differ from petroleum drilling:

- Higher temperatures can melt hard rubber fittings and valves on oil drill rigs and affect materials used for well casing.
- Higher pressures increase the risk of blowouts.
- Harder rock shortens bit life and reduces penetration rates.
- Higher brine content can cause corrosion and scaling on drilling equipment.

Drilling costs have increased significantly in the past few years. For example, a drilling company active at The Geysers reported that a typical 2,297 to 2,625 m well drilled 5 years ago (with only minor drilling problems) cost about $400,000. Today this same well would cost $1,000,000.[10] (See "Economics.")

Geothermal drilling R&D supported by the federal government, is emphasizing the improvement of existing drill bits, downhole motors, and drilling fluids to reduce drilling costs.[11] This effort includes:

- Final laboratory testing of roller cone drill bits that are expected to last about three times longer than conventional bits in geothermal environments.
- Laboratory testing of the Compax™ diamond bit. These synthetic industrial pellets provide a more economical means for cutting into hard rock formations.
- Design and laboratory testing of a diamond chain drill bit capable of high penetration rates in hard igneous rocks. This bit hydraulically advances an indexed chain to bring new cutting surfaces into place downhole without removing the entire drill string. The concept could reduce total drilling costs by 10 percent or more.
- Development of improved bearings and seals to extend the operation time of downhole motors used for drilling and pumping geothermal fluids out of a well.

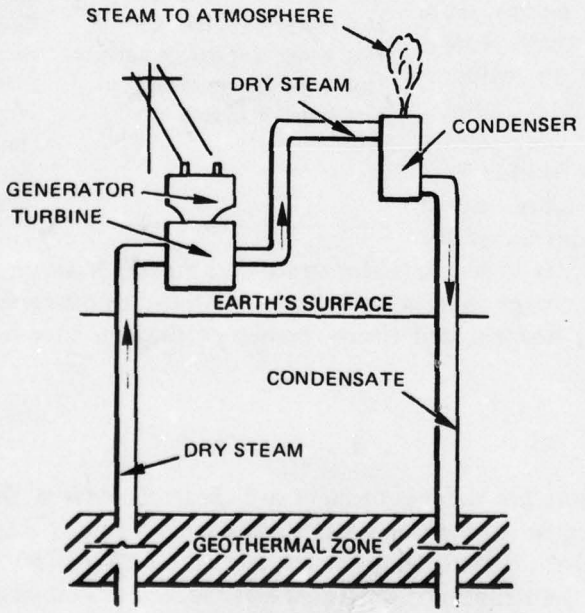
PRODUCTION AND CONVERSION

Hydrothermal Convection Systems

Vapor-Dominated Systems

In vapor-dominated systems, the geothermal steam can be used directly in a turbine generator. The technology for this type of system is well-known, largely because there are not as many technical difficulties as there are for liquid-dominated systems. Most of the experience gained in the United States has been at The Geysers in California, the largest geothermal installation in the world. It is a KGRA consisting of 163,428 acres, of which 11,450 acres are federally owned. Total generating capacity is now 500 MWe.

The first attempt to develop The Geysers' power potential was made in 1922. In 1956, the Magma Power Company and the Thermal Power Company, working jointly, found that geothermal steam could be produced economically. The Pacific Gas and Electric Company contracted to build a power plant and buy steam from the Magma-Thermal wells. In 1967, the Union Oil Company of California joined with Magma-Thermal in a project to drill for and produce steam (see Figure 9-6). Two new units are now being built, and the Pacific Gas and Electric Company is awaiting authorization to construct two other units, raising total generating capacity to about 1,000 MWe by 1980.



Source: U.S. General Accounting Office, "Problems in Identifying, Developing and Using Geothermal Resources," 6 March 1975.

Figure 9-6. THE GEYSERS DRY STEAM SYSTEM

About 900,000 kg of steam per hour are needed for every 110 MWe generated at The Geysers, an amount supplied by about 14 wells delivering steam to the turbine generators at 180°C and 7 kg/cm³. The net thermal efficiency is 14 to 16 percent. The lifetime of a well ranges from 2 to 20 years, and averages 15 years. As individual well pressures decrease, new wells must be drilled to maintain an adequate steam supply to the turbines.

Although dry steam represents a technically and economically acceptable energy source, its potential may be severely limited by its availability, since dry steam is not a replenishable resource and no commercial dry-steam fields except The Geysers have been identified in the United States.[12]

Liquid-Dominated Systems

Liquid-dominated systems can be developed as energy sources for electrical power generation if fluid temperatures and pressures are adequate. Nonelectric applications, such as space heating and process heating, vary widely and occur throughout the world. Liquid-dominated reservoirs often contain minerals that can be extracted to provide raw materials and/or fresh water for agricultural use (see Table 9-4 and Figure 9-7).

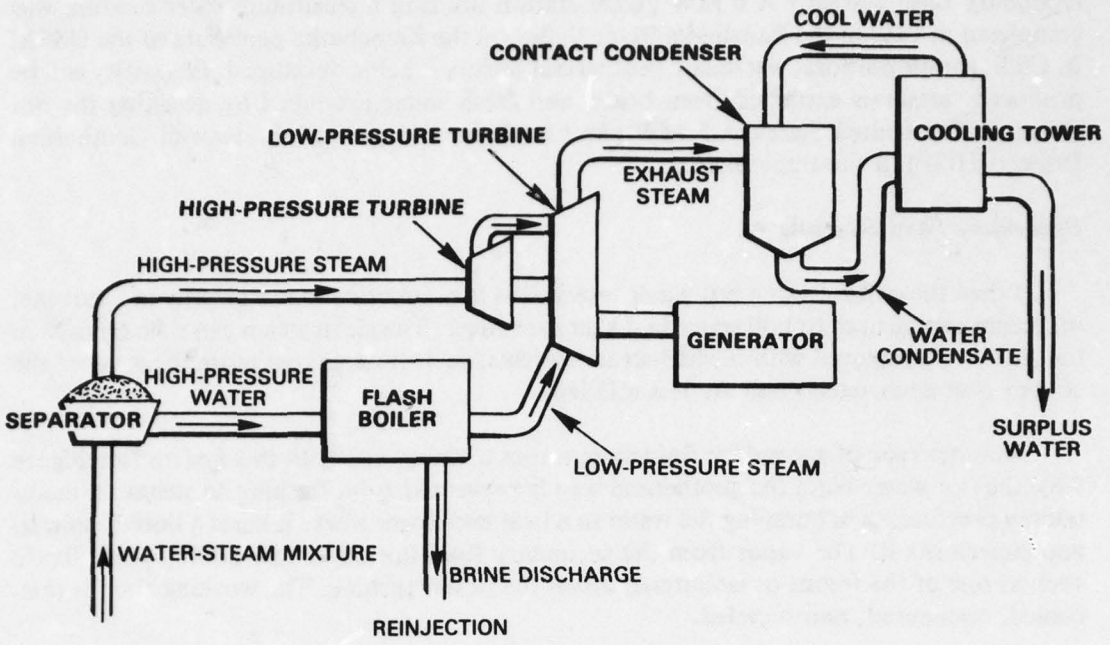
Table 9-4. TYPES OF GEOTHERMAL POWER PLANTS

Heat Source	Generation Mode
Dry steam	Steam turbine
Hot water (T > 180°C)	Steam turbine
Hot water (T < 150°C)	Binary cycle
Hot water (moderate salinity)	Hybrid cycle
Hot brine (pressurized)	Binary cycle
Hot brine (flashed)	Total flow concept:
	Impact turbine
	Helical screw expander
	Bladeless turbine

The end use of energy from liquid-dominated geothermal systems depends largely on temperature. The temperature ranges, divided arbitrarily, are: above 150°C for generation of electricity (binary systems may allow use of somewhat lower temperatures for generating electricity), 90°C to 150°C for space and process heating, and below 90°C for local use where better energy sources do not exist.[13] Multipurpose applications occur where process heating, space heating, and electric power production have been integrated in the same overall system.

Flash-Steam Systems

When high-pressure hot water is brought to the earth's surface, the pressure reduction can cause 13 to 25 percent of the hot water to flash into steam. (Simple flash systems are probably useful only for reservoir temperatures exceeding 200 to 250°C.) The water-steam mixture that flows to the wellhead is separated and the steam is piped to the steam turbines of a power plant. Additional steam can be produced from flashing again at a lower pressure, and the steam then can be introduced to a low pressure section of the power turbine to increase total power output. The residual hot water can be reinjected into the reservoir, desalted, or used for process heating.



Source: University of Oklahoma, Science and Public Policy Program, "Energy Alternatives, A Comparative Analysis," May 1975.

Figure 9-7. GEOTHERMAL POWER PLANT

The first electric power generator in the world using geothermal energy was from a vapor-dominated system. It began operating in 1904 in Larderello, Italy, and commercial production began in 1912. The present electrical power capacity of the area is 38 MWe.

Commercial flashed-steam systems began operating in New Zealand in 1958. About 180 MWe are being generated in the Wairakei-Broadlands field where the fluid temperatures are about 260 °C and around 20 percent is flashed to steam for power production. A plant to produce 150 MW also is being built at Broadlands.

Two 37.5 MWe turbogenerators are operating in a geothermal field in Mexico near the volcano of Cerro Prieto. Fluid temperatures are 300 °C or more, and salinities are 15,000 to 25,000 ppm. This facility is in the same geothermal resource area as the Imperial Valley of California (Salton Trough) and is important for providing data on operating with highly corrosive geothermal brine. An ultimate capacity of 400 MWe is expected there.

Japan has numerous active geothermal regions. Five of these are producing electricity using flash-steam systems: Otake (13 MW), Matsukawa (22 MW), Onuma (10 MW), Onikobe (25 MW), and Hatchoboru (50 MW). Japan's "Sunshine Project" is an aggressive program of geothermal investigation, which has a goal of 1,000 MW geothermal generating capacity by 1982 and 2,000 MW by 1985.

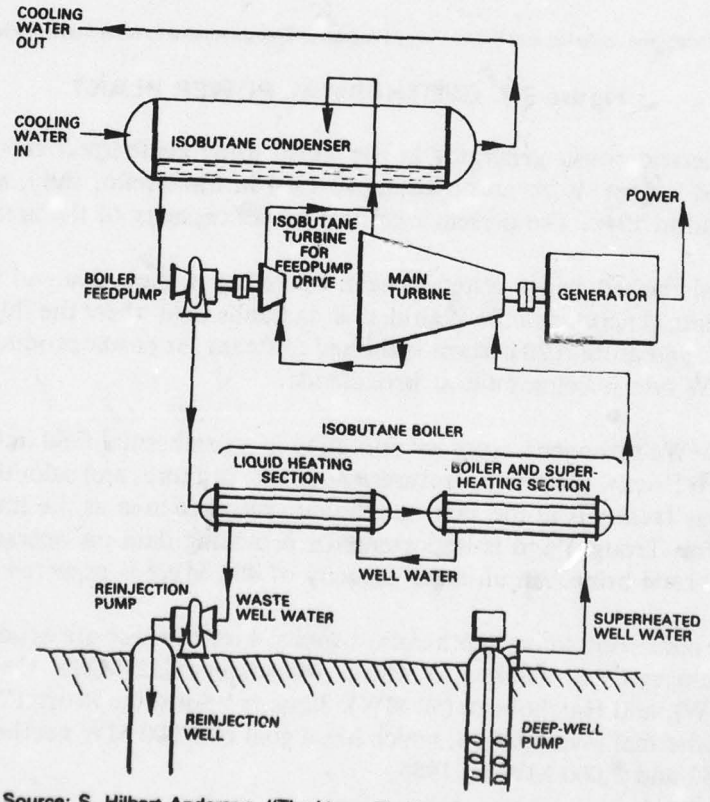
A 60 MW power plant has been in operation since 1976 in the Ahuachapan field in El Salvador; the plant will soon be increased to 80 MW capacity through the development of a

secondary flash system.[2] A 6 MW power station utilizing a steam-hot water mixture was completed in 1967 in the Pauzhetka River Valley on the Kamchatka peninsula of the USSR. In Chili, a multipurpose, wet-steam geothermal facility is being developed. Electricity will be produced, minerals extracted from brine, and fresh water produced by desalting the hot water. In the United States, a 5 MW plant is planned as part of the Hawaii Geothermal Project (HGP) in the Puna district.

Secondary Fluid Systems

When the steam from a hot water reservoir is too corrosive to use directly in a turbine, the steam can be used to boil water in a heat exchanger. The clean steam can then be used in the turbine. Compared with flashed-steam systems, such systems cost more (because of the cost of heat exchangers) and are less efficient.

Another type of secondary fluid system uses a binary cycle. In this system (see Figure 9-8), the hot water from the geothermal well is prevented from flashing to steam by maintaining pressure, then pumping the water to a heat exchanger where it heats a liquid, boils it, and superheats it. The vapor from the secondary fluid (usually a low-boiling-point liquid such as one of the freons or isobutane) drives the power turbine. The working fluid is then cooled, condensed, and recycled.



Source: S. Hilbert Anderson, "The Vapor-Turbine Cycle for Geothermal Power Generation," *Geothermal Energy* (Stanford University Press, 1973).

Figure 9-8. BINARY-CYCLE SYSTEM

Binary-cycle systems have an estimated efficiency of 10 percent or more and may be more efficient thermodynamically than flash systems for geothermal reservoirs with temperatures ranging from 150 to 230°C. Because it is a closed-loop system, the possibility of releasing noncondensable gases or brine chemicals is reduced greatly. A disadvantage is that the binary system requires an additional external water supply or a dry cooling tower.

The first geothermal power plant using a binary-cycle system was the Paratunka Station (0.68 MWe) on the east coast of Kamchatka, USSR, which operates on Freon. The reservoir temperature there is 81°C and the salinity of the fluids is low.

In Niland, California, a geothermal loop experimental facility has been operated since May 1976 by San Diego Gas and Electric Company with government support. Although the turbine and generator are not present, the facility is sized to generate 10 MWe using a flash/binary cycle. By April 1977, the facility had operated successfully for 2,600 hours using high-temperature, high-salinity brine. Long-term tests will provide the engineering data needed to design commercial plants.

Magma Power Company, San Diego Gas and Electric Company, and Standard Oil Company are working jointly to design, install, and operate an 11,200 kW (net) dual-cycle binary plant at East Mesa, California. The "Magnamax Process" prototype, scheduled to be operational in 1978, is designed to operate with 175 to 200°C geothermal brine. Republic Geothermal, Inc., is conducting extensive test and evaluation work at East Mesa and a 48 MWe (net) power plant is in the final design stage.

The Electric Power Research Institute initiated a project involving the conceptual design of an advanced binary conversion process. A 45 MWe (net) demonstration plant, designed by San Diego Gas and Electric Company, will be built at Heber, California, where temperatures (180°C) are representative of many liquid-dominated reservoirs in the western United States. The plant, expected to cost $42 million, is scheduled for start-up in mid-1981. The Heber plant would be the first large-scale power generating facility in the United States utilizing liquid-dominated geothermal resources and the first large-scale plant in the world using the binary energy conversion process.[14]

The Idaho National Engineering Laboratory (INEL) has plans for a 5 MWe thermal loop facility using the moderate-temperature (150°C), low-salinity reservoir at the Raft River site near Malta, Idaho, where a 60 kW binary unit is now on line and has been operating successfully for several months.[15] Conceptual designs for a dual boiling binary-cycle system are completed. The first unit will use available hardware, while the second will use advanced heat exchangers and related advanced technologies.

Other DOE-funded projects involve studies to develop new or improved heat exchangers, particularly direct-contact heat exchange between geothermal brines and binary-cycle working fluids. Such systems would mitigate greatly the scaling and corrosion problem and would cost less than conventional shell-and-tube types.

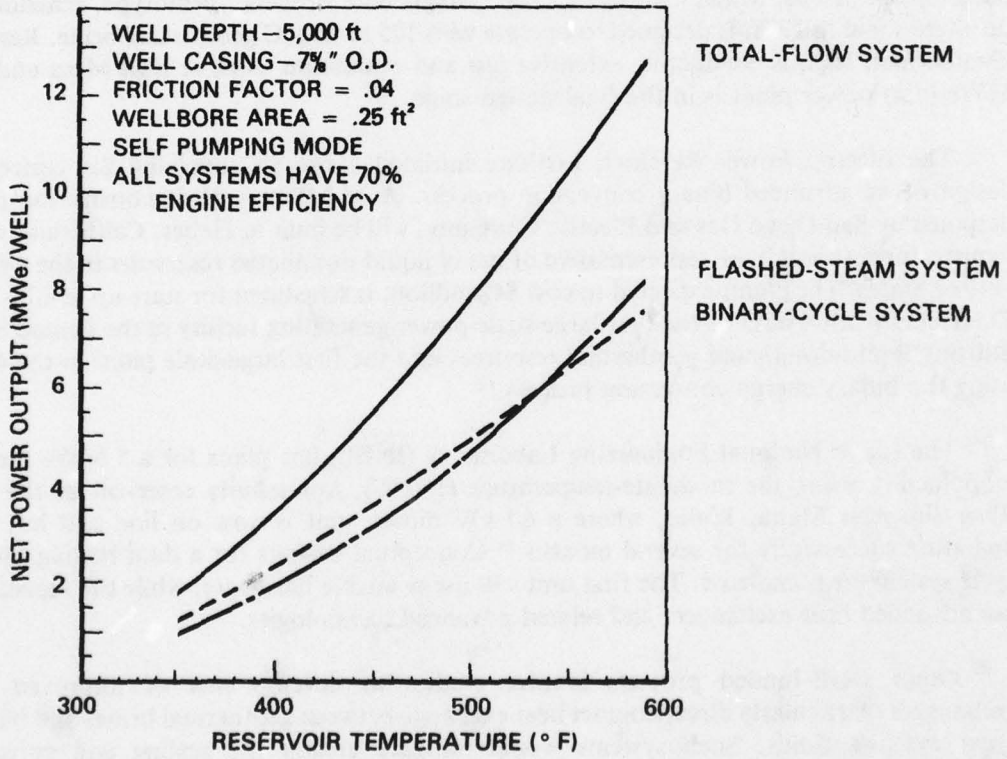
The Aerojet Energy Conversion Company, with DOE funding, has demonstrated a self-cleaning heat exchanger called Advanced Geothermal Primary Heat Exchanger (APEX)

and concluded that it was totally effective in preventing scale when operated on a continuous basis.[16] Sperry Research Center, Maine, is developing a system with DOE funding which may improve binary systems by as much as 35 percent. Freon 114 is circulated through heat exchanger bundles at varying depths in the well to produce vapor. The system's greater efficiency is derived from the addition of heat at differing pressures so that the thermal characteristics of the brine can be matched with the characteristics of the working fluid.[17]

The Lawrence Livermore Laboratory is conducting corrosion and materials studies at Niland. The Bureau of Mines Material Testing Facility at East Mesa and Niland also conducts corrosion and materials tests.

Total-Flow Systems

In a total-flow system, a two-phase working fluid, hot water and steam, is expanded through a nozzle into a turbine, making use of mechanical as well as heat energy. Theoretically, it could produce significantly more power than other systems given the same reservoir temperature (see Figure 9-9). Although this is not a new concept for converting geothermal energy to electric power, there have been no practical applications studied until recently.



Source: Lawrence Livermore Laboratory, University of California, "The Lawrence Livermore Laboratory Geothermal Energy Development Status Report, January 1974-January 1975," February 1975.

Figure 9-9. COMPARISON OF GEOTHERMAL POWER SYSTEMS

The Lawrence Livermore Laboratory is developing the total-flow concept. In 1977, it reported a new two-phase expander had been developed successfully. Generally, the program focuses on the development of systems for the recovery and conversion of energy stored in hot water deposits containing more than 3 percent total dissolved solids. These high-salinity brines pose formidable problems because of precipitation, scaling, corrosion, erosion, and brine handling and disposal. The goal of the program is a full 10 MWe experimental power plant system to become operational in 1980.[18]

Recently, Biphase Energy Systems successfully operated a two-phase rotary separator for 117 hours in a high-salinity environment. They concluded that, when applied to a two-stage flash system, the design would show a 20 percent increase in power output with a 12 percent specific cost reduction.[19]

Hot Igneous Systems

Extraction from Magma

Technologies for extracting energy from magma are at the preliminary stage of development. Techniques being studied include:

- Insertion of a heat exchanger into a magma source with surface conversion to electric power.
- Use of the reducing nature of magma to produce transportable fuels such as hydrogen and methane.[1]

Hot Dry Rock Deposits

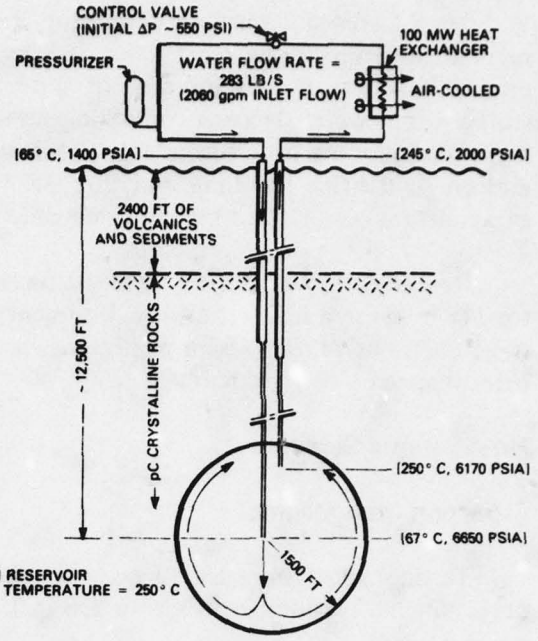
Most hot dry rock deposits are more than 15,250 m deep. Some shallow deposits exist, however, and are being studied at Coso Hot Springs, California, and on the Lemez Plateau of New Mexico near Los Alamos.

Since 1972, the Los Alamos Scientific Laboratory of the University of California, under the auspices of DOE, has been developing methods to extract energy from hot dry, impermeable rock, such as the granite of the western and northern United States. In the Los Alamos concept, a man-made geothermal reservoir would be formed by drilling into hot rock, then creating a large surface area for heat transfer within the rock by using large-scale hydraulic-fracturing techniques developed by the oil industry. After a circulation loop is formed by drilling a second hole into the top of the fractured region, the heat contained in the reservoir would be brought to the surface by the buoyant circulation of water, with no need for pumping. The water in the loop would remain liquid due to pressurization at the surface, thereby increasing the rate of heat transport up the withdrawal hole compared with the rate possible with steam (see Figure 9-10).

Preliminary experiments and analyses indicate that thermal stresses created by cooling the hot rock in such a man-made reservoir may gradually enlarge the fracture system so that its useful lifetime will be extended far beyond the planned 10 to 15 years provided by the original reservoir. If these thermal-stress cracks grow preferentially downward and outward

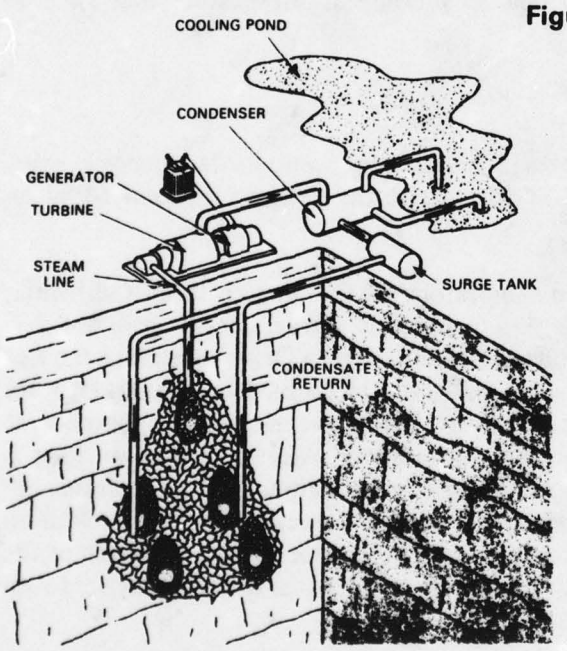
into hotter rock, as seems probable, the quality of the geothermal source may actually improve as energy is withdrawn.[20]

The Los Alamos concept is being demonstrated in an area about 20 miles west of Los Alamos, New Mexico. Drilling of the first well began in February 1974. The well reached a depth of 2,933 m; the bottom hole temperature was 200°C. A near vertical, 122 m radius fracture was created with hydraulic pressure near the bottom of this hole. A second hole, located 77 m from the first, intersected the fracture in October 1975 at a depth of 3,065 m with a bottom hole temperature of 205°C.[21] Cold water is circulated through the fractures at 6.89 $\times 10^6$ N/m^2 (1,000 psi) to be heated, then flows from the second hole at 130°C. Installation of a 10 MWe heat exchanger in late 1977 initiated study of the feasibility



Source: M. C. Smith, "Los Alamos Scientific Laboratory Dry Geothermal Source Demonstration Project," 1975.

Figure 9-10. LOS ALAMOS CONCEPT FOR EXTRACTION OF ENERGY FROM HOT DRY ROCK



Source: Noyes Data Corporation, "Geothermal Energy," 1975.

Figure 9-11. PLOWSHARE CONCEPT OF GEOTHERMAL HEAT EXTRACTION

of a closed-loop pressured water system and determination of whether the circulation temperature decreases. After modifications were made, the loop was run almost continuously between January and April 1978. The potential problem of precipitation of minerals, such as silica, into the system also is being studied.

Another method of fracturing hot dry rock, the Plowshare Concept, is being studied by a team from Lawrence Livermore Laboratories, DOE, Battelle Pacific Northwest Laboratories, American Oil Shale Company, and Westinghouse Electric Corporation. This method uses nuclear explosives followed by injection of water into the reservoir. It might also be used to stimulate enough steam production in steam fields to permit more economical development (see Figure 9-11).

A preliminary concept being considered in Sweden was introduced recently. The concept involves exploitation of hot dry rock through a single drill hole. If technically feasible, this technique would be more economically attractive than systems requiring the drilling of two or more drill holes.[22]

GEOTHERMAL ELECTRIC POWER GENERATION POTENTIAL

An informal survey made by EPRI of over 15 utilities in the United States in 1978 showed a probable growth of geothermal electricity power capacity to 7,475 MWe by 1995 as shown in Table 9-5. This is a 100 percent increase over the results of a similar survey made in 1977.[23]

Present worldwide, installed geothermal electric power generating capacity is 1,325 MWe. The estimated total energy use rate for nonelectric applications throughout the world is 7,000 MWth.[2] A recent study made by EPRI based on analytic computations and on worldwide questionnaires estimated the geothermal electric energy potential with current technology to be roughly 1,200 GW cen(e) (gigawatt-centuries, electric).[2] Estimated values for 1985 based on questionnaires are shown in Table 9-6.

Table 9-5. 1978 EPRI SURVEY OF ELECTRIC UTILITY FORECASTS OF GEOTHERMAL POWER CAPACITY

	Capacity (MWe)				
	1977[a]	1985[b]	1990[b]	1995[b]	2000[b]
Arizona/New Mexico	0				
Announced		50	50	50	50
Probable		150	250	450	450
Possible		250	450	800	1,400
California	502				
Announced		1,969	2,969	3,569	3,869
Probable		2,409	4,804	6,423	7,473
Possible		2,969	6,614	9,123	10,723
Idaho/Oregon/Washington	0				
Announced		0	0	0	0
Probable		5	60	200	500
Possible		55	200	800	1,500
Nevada/Utah	0				
Announced		55	55	55	55
Probable		110	320	430	430
Possible		110	320	430	540
Total	502				
Announced		2,019	3,019	3,619	3,919
Probable		2,664	5,414	7,473	9,023
Possible		3,374	7,664	11,323	14,723

[a]Actual.

[b]Estimated.

Source: Paul Kruger and Vasel Roberts "Utility Estimates of Geothermal Electricity Generating Capacity," in Geothermal Resources Council Annual Meeting Transaction, 25-27 July 1978, Vol. 2.

NONELECTRIC APPLICATIONS

Because of increasing prices for conventional fuel supplies, nonelectric applications of geothermal energy are becoming more cost competitive. Such applications are therefore receiving increased attention in the United States and throughout the world. Nonelectric or direct uses of geothermal energy generally employ lower temperature, lower heat content, and shallower geothermal waters than those used in electric power generation. Cooler, shallower ground waters are less mineralized, and the volume rate of fluid produced is usually smaller in direct use than in power generation.

Table 9-6. ELECTRICITY GENERATING CAPACITY FROM GEOTHERMAL RESOURCES[a]

Country	1976 Installed Capacity (MW)	1985 Estimated Capacity (MW)
United States	502	3,000
Italy	421	800
New Zealand	190	400
Japan	68	2,000
Mexico	75	400-1,400
USSR	5.7	–
Iceland	2.5	150
Turkey	0.5	400
Canada	–	10
Costa Rica	–	100
El Salvador	60	180
Guatemala	–	100
Honduras	–	100
Nicaragua	–	150-220
Panama	–	60
Argentina	–	20
Portugal	–	30
Spain	–	25
Kenya	–	30
Indonesia	–	30-100
Philippines	–	300
Taiwan	–	50
Total	1,325	8,335-9,375

[a]Based on questionnaires.

Source: Electric Power Research Institute, "Geothermal Energy Prospects for the Next 50 Years," Preliminary Report to the World Energy Conference, ER-611-SR, February 1978.

One primary nonelectric application of geothermal energy is space heating. When used for heating, hot water from geothermal resources can be piped directly to the point of use. If the hot water is a highly corrosive brine, heat exchangers can be used.

Operating costs for geothermal space-conditioning systems are low when compared with fossil-fueled systems. A depreciation time of 20 to 30 years generally is used for economic evaluations.[24] In Klamath Falls, Oregon, which has had a small geothermal district heating system for many years, it costs about $50 to heat a single residence for a year including pumps, repair, etc.[25] The initial capital costs to build the thermal distribution and discharge system are high, however. Factors influencing costs include resource temperature, soil and topographic conditions, accessibility for installing the systems, load density within the distribution area, and distance between the resource and use points. Economical transport of hot water is usually limited to a maximum of 160 km although new piping materials are being studied. Special materials and equipment needed to minimize corrosion and scaling problems also can add to the overall cost of the system.

As of 1972, the USSR was the world's largest user of geothermal energy for heating, greenhouse operation, and industrial uses. More than 28 geothermal fields are in use in the USSR; total nonelectric use of geothermal energy is estimated to be about 440 MW. In Iceland, geothermal energy supplies about 2.5 GWh/year for space heating, serving over 100,000 people. Almost all of the buildings in Reykjavik, the capital, use geothermal energy for spacing heating.

Geothermal energy is used extensively for direct heat in Hungary. At the end of 1974, 433 wells were producing thermal waters above 35 °C to produce over 1,000 MW of thermal energy. Other systems are being developed.[2]

Geothermal space heating in France is used for 12,000 dwellings and is equivalent to about 170 MW; a total of 5,000 MW is projected for 1985. A new housing development is under construction near Paris; 5,000 to 6,000 units will be heated using titanium heat exchangers with a geothermal system.

In the United States, use of geothermal energy for heating has been minimal, about 40 MW for recorded applications. In addition to the system in Klamath Falls, Oregon, the low-temperature geothermal resource near Boise, Idaho, has been used to a limited extent for residential and commercial space heating for over 85 years. Interest in direct heat applications is increasing, however. DOE is funding 15 demonstrations of direct use including one in Boise, Idaho, for space heating of 11 commercial buildings. INEL is planning a demonstration project involving space heating of 38 public buildings in Boise (similar to providing heat for 4,000 average homes).

Other direct applications for hot water include industrial process heating, heating greenhouses, fish farming, soil warming in agribusiness, and using the water as a source for extractable minerals. With several industrial participants, INEL is investigating the large intermediate-temperature hydrothermal resource in the Raft River Valley, Idaho. This project could become the largest process heat utilization of geothermal energy in the United States, with a potential energy use rate of 45 MW.[26] Table 9-7 lists examples where geothermal energy is being used in industrial processes. Other industrial applications, such as fluidized-bed, low-temperature drying in potato processing, are also being studied by INEL.[27] At Kawerau, New Zealand, geothermal energy is being used for the combined power production and direct heat needs of a pulp and paper mill.[2]

Table 9-7. EXAMPLES OF EXISTING AND PLANNED APPLICATIONS OF GEOTHERMAL ENERGY FOR PROCESS USE

Product	Country	Application	Form of Geothermal Energy
Pulp and paper	New Zealand	Evaporating, digesting, drying	Primary and secondary steam
Timber drying and seasoning	New Zealand, Iceland	Drying, seasoning	Steam, hot water
Diatomite processing	Iceland	Drying, heating,	Steam deicing
Hay drying[a]	Iceland	Drying	Hot water
Seaweed drying	Iceland	Drying	Hot water
Washing of wool	Iceland, USSR	Heating and drying	Steam
Curing and drying of building material	Iceland	Heating and drying	Steam, hot water
Stock fish drying	Iceland	Drying	Hot water
Salt recovery from seawater	Japan	Evaporation	Steam
Salts from geothermal brine[a]	Iceland	Evaporation	Steam
Boric acid recovery	Italy	Evaporation	Steam
Brewing and distillation	Japan	heating and evaporation	Steam
Food	United States	Vegetable dehydration	Hot water

[a]Planned.

Sources: B. Lindal, "Geothermal Energy for Space and Process Heating," *Energy Technology Handbook* (New York: McGraw-Hill Book Company, 1977), and "Plant Uses May Surface for Geothermal Energy," *Chemical Engineering,* 5 June 1978.

Extraction and upgrading of minerals from geothermal brine could enhance the cost-effectiveness of geothermal energy production in areas such as the Salton Trough in California. Very little R&D effort has been expended toward this concept, however, with the exception of a desalination project being conducted by the Bureau of Reclamation.

U.S. GEOTHERMAL ACTIVITIES

Under the Geothermal Energy Research, Development and Demonstration Act of 1974, a coordinated federal program of energy RD&D must be carried out. The objective of the federal geothermal program is "to stimulate private and local power authorities to develop geothermal resources as reliable, operationally safe and environmentally acceptable energy sources for the production of electricity and direct heat applications."[11] Over the last few years, federal funds allocated to geothermal development have increased considerably. The Energy Research and Development Administration (ERDA)—now part of DOE—budgeted only $31.4 million in FY 1976. For FY 1979, DOE has an approved budget of $156.2 million for geothermal development.

The federal geothermal program is targeted at reduction of uncertainty in assessments of the available resource base, on both regional and site-specific scales. The program is intended to stimulate the commercial development of hydrothermal resources by the mid-1980s, with rapid growth through 2000. The effort includes an RD&D program to reduce technological and environmental risks, a loan guaranty program to reduce lenders' risks, and policy measures to reduce the institutional uncertainties. The federal effort also includes development of measures for stimulating the initial development of geopressured resources by the mid-1980s, and encouraging continued growth. Advanced technological R&D is another important aspect of the federal program.

DOE is the lead agency for coordinating the federal geothermal energy program and heading the Interagency Geothermal Coordinating Council. Other member agencies are the Department of the Treasury, Department of the Interior (DOI), Environmental Protection Agency (EPA), National Science Foundation (NSF), and Department of Agriculture.

DOE is responsible for a major portion of technology development projects involving studies of the major requirements for extraction and utilization of each resource type. These projects include improved drilling technology, reservoir engineering, conversion equipment development, and pollution abatement technology development. Commercial-scale (50 MWe) demonstration plants are planned to exhibit the economic feasibility and environmental acceptability of a geothermal resource.

DOE is also responsible for developing the incentives, institutional relationships, and policies necessary to encourage industrial commitment. Incentives include a leasing program to make federal lands available for geothermal development (DOE is responsible for promulgating regulations under the Geothermal Steam Act of 1970 related to leasing policies); the geothermal loan guarantee program to reduce financial risk; and policy research to resolve the social, legal, economic, and environmental problems associated with development of these energy resources.

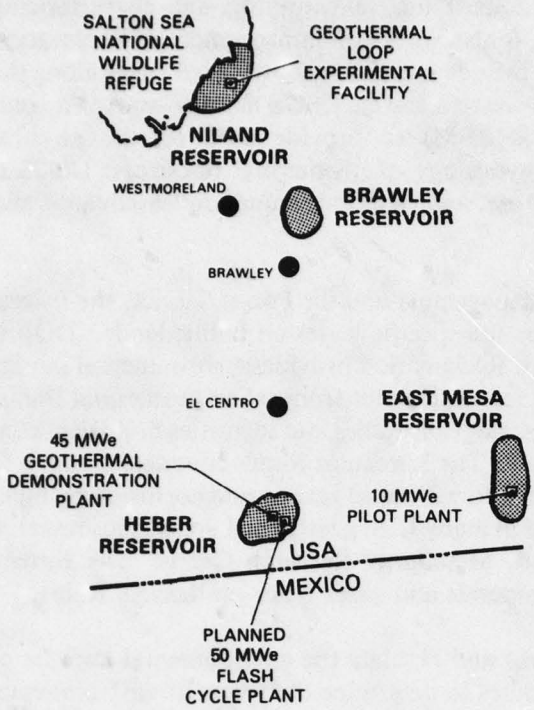
DOI, through USGS, is responsible for identifying, inventorying, and characterizing geothermal resources available to the nation. It also works on improvement of exploration technology and assessment. Current activities include mapping geopressured zones along the Gulf Coast and studying geothermal areas in western states. USGS has also started a computerized geothermal resources file (GEOTHERM) to provide data on the physical characteristics, geology, geochemistry, and hydrology of geothermal resources. USGS is responsible for determining geologic, engineering, and economic values on leased lands and supervising lessee operations.

Also within DOI, the Bureau of Land Management and the Forest Service, the federal land management agencies, issue and monitor site-specific leases on public lands. (DOE is responsible for leasing policies.) The Bureau of Reclamation provides environmental impact assessments and has studied methods to produce fresh water from saline geothermal fluids. The U.S. Fish and Wildlife Service conducts ecological studies and identifies biological consequences of geothermal resources development. The Bureau of Mines conducts research to develop the corrosion-resistant materials needed to withstand scaling and corrosion by high-temperature, high-pressure saline fluids found in many U.S. geothermal areas. This research is conducted at the College Park, Maryland, Metallurgy Research Center. The Bureau develops technology to recover by-product minerals and gases from geothermal fluids.

EPA has statutory responsibility to assess and regulate the environmental impacts of geothermal development. It is conducting studies to determine the scope of environmental problems and possible solutions.

Major geothermal development projects, being done by both government and private industry, are under way in several states:

- *Alaska.* Several low-temperature water-dominated springs exist and geothermal water has been used on a small scale for space heating, bathing, and growing vegetables. One area showing significant potential for production of steam is along the Aleutian Island chain. The federal government is drilling and testing heat flow wells at Adak.
- *California.* The Geysers area, already highly developed, produces more than 500 MWe from hot dry steam; production is likely to exceed 1,000 MWe. A geothermal area having significant commercial potential is the Salton Trough, or Imperial Valley, region in California (see Figure 9-12). The Imperial Valley has a potential geothermal energy resource of 10,000 to 20,000 MWe, of which 4,500 MWe could be developed with present technology. There are at least four major geothermal reservoirs in the Valley: Niland, where the temperature, enthalpy, and salinity of the brine are high; and Brawley, Heber, and the East Mesa, where the temperature, enthalpy, and salinity of the fluids are lower. Numerous wells have been drilled in the Imperial Valley and several demonstration plants are being planned by both private and public parties. (See "Production and Conversion" in this chapter.) In Long Valley, several promising holes have been and are being drilled. Calistoga has more than 60 wells producing hot water used for space heating. In Amedee, two wells are used for greenhouse operations and further exploration is probable. At the Coso geothermal area, the U.S. Navy and DOE are drilling experimental wells to deter-



Source: C. R. Swanson, "San Diego Gas and Electric Company's Geothermal Program," in Geothermal Resources Council Annual Meeting Transaction, 25-27 July 1978, Vol. 2, p. 639.

Figure 9-12. GEOTHERMAL SITES IN IMPERIAL VALLEY, CALIFORNIA

mine the potential for geothermal electrical generation. Preliminary studies indicate the Coso area could produce as much as 4,000 MWe.

- *Hawaii.* The potential of using geothermal energy on Hawaii is being evaluated. A 5 MW flash steam power plant near Hilo is scheduled for completion in August 1980.
- *Idaho.* Seventeen wells, four of which are production wells, yielding low-temperature water have been drilled at Raft River. A 5 MWe plant, demonstrating a dual binary-cycle system, will be built at Raft River in 1980. (See "Production and Conversion" in this chapter.) Several nonelectric applications are also being studied at the Raft River site, for example, the use of geothermal heat for industrial processing. Two wells at Boise have been supplying water for space heat since 1883 and expansion of this use is under way.
- *Louisiana.* The chemical composition of the geopressured water and gas in an abandoned gas well on the Gulf Coast has been analyzed.
- *Montana.* Extensive geological and geophysical surveys were carried out in the Marysville geothermal area. Drilling of a deep test well indicated a hydrothermal convection system at 100°C with commercial potential.
- *Nevada.* More than 17 holes have been drilled in four areas of Carson Desert. Further drilling and testing are expected in two of these areas, along with wildcat drilling in adjoining areas. Twelve or more holes were drilled in the Beowawe area and temperatures of over 200°C were encountered; continued drilling is expected. Dozens of shallow wells have been drilled in the Steamboat Springs area, and some are being used for space heating. Deeper holes may be drilled to seek hotter water. Construction of a food processing plant that uses geothermal energy for vegetable dehydration was completed near Reno. This facility is the first to begin operating under the federal loan guaranty program. The use of geothermal energy at this plant replaces about 117 million ft^3 of natural gas per year.
- *New Jersey.* Drilling began in June 1978, at Fort Monmouth. About 50 additional wells will be drilled in New Jersey, Delaware, Maryland, Virginia, North and South Carolina, Georgia, and Florida to determine the best site for a 2 km well.
- *New Mexico.* At least 15 holes have been drilled and nine producible wells have been

found in Valles Caldera. This water is hot enough to flash into steam at the surface. Further drilling is likely and DOE is negotiating with a utility company to build a 50 MWe power plant. The feasibility of a hot dry rock system is being demonstrated at the Los Alamos project.

- *Oregon.* Some 400 wells have been drilled at Klamath Falls for space heating of approximately 400 structures, using downhole heat exchangers. Proposals for further development of a geothermal district heating system are being considered.
- *Utah.* Six wells have been drilled; three of them near Roosevelt Hot Springs are good producers of hot liquids. Potassium-argon dating studies conducted by USGS in 1976 produced strong evidence of good geothermal potential at Roosevelt Springs.[25] Further exploratory drilling is probable and power generation is being considered.

DEVELOPMENT CONSIDERATIONS

Environmental Considerations

Although geothermal energy has been lauded in the past as a "clean" energy source with few environmental problems associated with its development, only a small amount of environmental data on the use of geothermal energy is available, and there is almost no field experience with many of the conversion technologies. However, the effects in most cases will be less than the impact of nuclear and fossil fuel systems.

The environmental effects are site-dependent, that is, the drilling takes place in the immediate vicinity of the power plant or other facility. Transportation is limited to pipes and power lines; pipes would extend no more than a few kilometers, and power lines would be limited by the small capacity of most geothermal plants. Most negative impacts would occur because of drilling and construction during the development period. The environmental effects of geothermal development are also site-specific because the impacts depend on the type of geothermal system being developed, including its characteristics, for example the geochemistry, geology, and topography, and on the type of technology used to develop the resource at that site (see Table 9-8). Current government research activities include gaseous emissions research (mainly the control of hydrogen sulfide), subsidence control technology, noise effects, aquatic chemistry of toxic elements, toxic effects of heavy metals, and ecological studies.[5]

In general, the prospects appear favorable that many geothermal resources can be developed in an environmentally acceptable manner. The "fuel cycle" is short compared to many alternate technologies because no combustion is necessary. Furthermore, there is no requirement for off-site, submerged technologies such as mining, refining, enrichment, and fuel processing. Land use per unit of energy generated can be small in comparison to many alternate technologies, but the choice of sites for utilization is mandated by resource location. Possible competitive land uses and socioeconomic factors may therefore be critical factors in determining the acceptability of developing a particular geothermal resource.[28] This section summarizes some potential negative environmental impacts. Details are available in a variety of government publications as well as reports on environmental assessments of specific areas being developed in the United States.[29-34]

Table 9-8. POTENTIAL ENVIRONMENTAL IMPACTS OF GEOTHERMAL POWER PRODUCTION

Impact	Estimate of Probability	Technology/ Resource Type	Severity of Consequences
Land subsidence	moderate	hot water	variable—can be high
Induced seismic activity (earthquakes)	low	all	high
Air pollution resulting from discharge of noncondensable gases (e.g., hydrogen sulfide, carbon dioxide)	high	all except hot water binary fluid and other "closed-cycle" use of geothermal fluids	variable—depends on emission controls
High noise levels of drilling and plant operation	high	all; worst for vapor-dominated	moderate
Chemical or thermal pollution of surface and groundwaters	moderate	all; greatest probability with hot water	high
Well blowouts	low	hot water; vapor-dominated	moderate
Increased erosion and sedimentation resulting from site disturbance	high	all	moderate
Consumption of water for cooling purposes	high	hot water binary fluid, hot dry rock	high
Consumption of land for wells, power plants, transmission lines	high	all	moderate
Short-term climatic changes resulting from release of heated steam and carbon dioxide	high	hot water; vapor-dominated	low
Disturbance of habitat; alteration of ecosystems	moderate to high	all	moderate to low

Source: U.S. Environmental Protection Agency, "Western Energy Resources and the Environment: Geothermal Energy," EPA-600/9-77-010, May 1977.

Air Pollution

Noncondensable gases, such as hydrogen sulfide, carbon dioxide, methane, ammonia, and nitrogen found in the vapor phase of a geothermal source, could cause serious air pollution if released. Cooling tower emissions, such as boron, arsenic, and mercury, are also of concern. Hydrogen sulfide ranks as the most likely potential environmental hazard. The amount of hydrogen sulfide occurring in a system cannot be predicted based on the type of geothermal system (natural steam or hot water). It occurs at 16 times the toxic level in undiluted geothermal steam at The Geysers, although normally the gas is dispersed in the atmosphere before it reaches a toxic level. The amount of hydrogen sulfide released at The Geysers is less than a quarter of the EPA limits.

The Geysers' Unit 11 is the only geothermal power plant in the world to have ever been designed with hydrogen sulfide abatement in mind. Currently, abatement efficiency is about 70 percent.[35] Although the abatement equipment was designed for a natural steam system, it should be easily adaptable to flashed-steam systems.

Water Pollution and Depletion

Introduction of highly saline or toxic geothermal fluids to surface waters, resulting from the brine disposal, blowouts, or spills, could cause water and thermal pollution. This is of significant concern in California's Imperial Valley and in geopressured areas of the Gulf Coast. Reinjection of spent fluids into the reservoir greatly mitigates the risk. However, the feasibility of long-term, large-volume reinjection has not been demonstrated. Ground water contamination can result from interference with overlying fresh water aquifers during drilling and production.

The environmental effects of water depletion could be a problem where large amounts of cooling water are consumed. Binary-cycle plants, for example, normally require more cooling water than other types of geothermal plants.

Land Subsidence

Sinking of the earth's crust sometimes occurs when support fluids are removed from underground reservoirs. Geothermal development has already resulted in subsidence occurring in some areas. Of serious concern is the potential for subsidence occurring during development of geopressured resources, such as those along the U.S. Gulf Coast, because the quantity of water withdrawn during development of this type of geothermal system is enormous.[36] There is also potential for subsidence occurring in the Imperial Valley. Prevention of subsidence involves injecting replacement fluids, usually the spent geothermal fluids. Some experts believe that land subsidence and induced seismic activity are among the more significant impacts of geothermal development.

Seismic Activity

Changes in reservoir pressures can cause an increase in seismic activity. Although not well studied to date, either injection or withdrawal of large volumes of fluid may have a powerful enough effect on the stresses in a fault zone to cause a major earthquake. On the other hand, minor changes in seismic activity may relieve accumulated strain before a major earthquake occurs.

Noise Pollution

Noise can result during venting of geothermal steam through relief valves. Mufflers are being developed. Drilling, testing, and construction activities produce noise as well.

Land Modification

Most geothermal power plants would be in areas not now industrialized or urbanized, necessitating disruption of existing land use and possibly disturbing wildlife. However, it is also true that since such facilities would be smaller than most power plants, fossil or nuclear, and since the electricity or steam would usually not be transmitted great distances, the negative impacts on land use and wildlife would be minimal and restricted to the immediate area of the plant. Also, a developed geothermal field need not be incompatible with other

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land uses. In Italy, for example, farms, orchards, and vineyards are interspersed among the pipelines and wells. At The Geysers, cattle graze and wildlife live in areas immediately adjacent to the power plant. Geothermal wells would not be drilled normally in recreational areas, especially in federal and state parks.

Legal and Institutional Problems

In a 1975 workshop, the National Science Foundation reviewed legal problems associated with the development of geothermal sources.[37] Since then, the Institutional Barrier Panel has analyzed several problems in reports to the Geothermal Advisory Council. Some of the more serious institutional issues involve:

- Resource definition, which varies from state to state. In Hawaii and California, geothermal resources are defined as minerals; in Wyoming, as water resources.
- Ownership rights. Federal grants of public land retain mineral rights for the federal government, while some state grants include mineral rights.
- Control over use of water. Some states such as Oregon, California, and Colorado have laws that prohibit transporting water out of state.
- Overlapping and conflicting regulations and jurisdictions for permits, licenses, taxes, environmental control, etc., exist among federal, state, and local governments.
- Leasing complications. Since almost 75 percent of all KGRAs in the United States are beneath federally owned land, most of the leasing contracts must be negotiated through DOI. Industry representatives have criticized DOI's land classification and leasing policies, maintaining that, in many cases, they cause unwarranted delays in resource development.
- Drilling permit delays. Requirements for obtaining permits are time-consuming and restrictive, and there are numerous federal, state, and local government entities that must review the drilling plan, causing further delay and added costs.[38]
- Environmental problems. The lack of environmental impact data tends to discourage or delay acceptance of geothermal technologies.

Federal and state agencies have taken action to mitigate some of these problems. For example, the federal Interagency Geothermal Streamlining Task Force—created to assist the Interagency Geothermal Coordinating Council with analyzing each step in the existing leasing and permitting processes of the Bureau of Land Management, Forest Service, and USGS—is identifying sources of delay and suggesting alternative options.[39] The National Conference of State Legislatures is establishing the geothermal policy project to help states "establish a legislative and regulatory climate that encourages efficient development of geothermal energy while protecting the states' interests in their natural resources."[40] California and New Mexico enacted geothermal statutes in 1967 and other states followed in the 1970s. Some of these statutes were patterned after the Geothermal Steam Act of 1970. Other problems have resulted from more stringent or complicated legislative and regulative action in the states.[41]

Economics

Depending on the degree of salinity, drilling costs, condensing temperature, and the costing approach, estimates for power plant costs in the United States range from $400/kW to $650/kW. (In the Imperial Valley, the cost of field development is expected to range from $500/kW to $750/kW of installed capacity, with the cost of electric power estimated at 30 to 35 mill/kWh.) The overall average cost of fluid delivered at a plant is estimated at $0.60 to $1.00/million Btu. The oil equivalent energy cost would range from about $1.60 to $2.80/million Btu (at $13.50/bbl of oil and taking into account the difference in conversion efficiency of the conventional oil-fired plant compared with the geothermal plant).[42] Hydrothermal power plant costs are expected to be about the same as those for oil-fired plants, and annual operating and maintenance costs are expected to be about 4.5 percent of the plant's capital costs.[2]

Wells are expected to cost from $300,000 to $600,000. It has been estimated that assuming a base cost of $500,000 per well, a 40 percent reduction in well cost would result in a decrease in busbar energy cost of 15 to 23 percent depending on reservoir temperature. Geothermal well drilling costs in 1976 dollars ranged from $150/m to $300/m.[2] Both industry and the government are interested in improving well drilling technology since this could significantly increase interest in commercial development of geothermal resources.

As demonstration plants are built, costing will become more defined.[43] Current uncertainties include:

- The extent and characteristics of the resources for most potential areas are not known with enough accuracy to predict the exploration and drilling required for development, both of which can add significantly to the total investment and discourage industry and financial institutions from committing capital for development.
- Conversion efficiencies have not been proved for most systems suggested; these efficiencies will vary as the fluid temperatures vary from reservoir to reservoir.
- Costs for all forms of energy production are rising, making it difficult to compare geothermal costs with other energy sources.

The only geothermal operation in the United States generating data on the economics of developing a geothermal steam resource has been The Geysers. The Pacific Gas and Electric Company states that the cost of electric power produced from dry steam at The Geysers varies from plant to plant. In March 1975, the company provided information showing that the cost of power produced from Units 9 and 10 averages 5.325 mill/kWh at 80 percent capacity:

	Mill/kWh
Annual cost of steam	2.599
Annual operating costs	0.223
Annual fixed costs	2.503
Total	5.325

The company estimated (in March 1974) that the unescalated cost of power from Unit 13, when built, will average about 10.36 mill/kWh at 80 percent capacity. Although the cost of geothermal power is rising, it will remain lower than the cost of power produced from nuclear plants, which is estimated to be about 15.2 mill/kWh. Union Oil officials stated that the charge for geothermal energy was comparable with the charges for fossil fuels.

Many experts agree that "the technology and economics of The Geysers development must never be used as a measure of other locations having even modestly different characteristics."[44] In 1976 dollars, the cost of heat delivered to the power plant was approximately $0.60/million barrels of oil equivalent.

Known factors that may contribute toward making geothermal energy economically competitive with other forms include:

- Tax incentives. The U.S. Congress enacted legislation (the National Energy Act) in 1978 authorizing intangible drilling costs and a 22 percent depletion allowance for wells drilled after 31 December 1977. The act authorizes a 10 percent investment tax credit for businesses installing geothermal equipment and a residential energy credit of 30 percent of the first $2,000 and 20 percent of the next $8,000 for homeowners who install geothermal equipment.
- Continued and increased government support in R&D and federal loan guarantee programs.
- Willingness of industry to invest and of financial institutions to loan money.
- Successful compliance with EPA without prohibitive expenditures on environmental control technologies.
- Continued high costs for more conventional energy sources.
- Integrated operation by utility companies of geothermal power stations (from exploration to production) rather than purchase of steam or hot water from independent suppliers.
- Improved technology for drilling and conversion methods.
- Expedition of leasing permit and regulatory procedures. The National Energy Act authorizes the Federal Energy Regulatory Commission to order interconnection and wheeling for utilities or cogenerators installing power plants. Also, small geothermal facilities are now exempted from public utility regulation.

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10. SOLAR ENERGY

Solar energy is abundant and perpetually renewable, making it an ideal energy source in many ways. Solar conversion systems generate only small amounts of air and water pollution and negligible thermal pollution. Theoretically, a desert area of 120 km by 120 km would receive enough solar energy each year to meet the entire estimated U.S. energy demand for 1985. Actually, however, a much larger area would be required since available solar energy conversion devices are not totally efficient. The conversion efficiency of water and air heating panels is less than 70 percent, and is only 10 percent for photovoltaic solar cells or thermionic devices.

The most significant near-term application of solar energy is direct solar heating, while cooling and photovoltaic generation of electricity are considered mid-term and thermal generation of electricity, far-term. Heating and cooling buildings and heating water account for more than 25 percent of the total energy used in this country; significant amounts of heat energy are also required in industry for process utilization. Conversion of solar radiation to low-temperature solar thermal energy can provide a portion of the energy now supplied by expensive, scarce fossil fuels. Solar space heating and hot water heating are both technically feasible, while solar cooling is still in the developmental stage.

Electrical power, which comprises about 30 percent of the total energy used in the United States, can also be generated using solar conversion technology. Both thermal and photovoltaic conversion systems, although still in their infancy, are being given intense developmental attention.

SOLAR RADIATION

Solar radiation is neither a continuous nor a constant source of energy. Relative to any point on earth, the sun crosses the sky at 15 degrees/hour, reaching a maximum altitude at midday. Because of the earth's 23.5 degree tilt, the solar altitude (at midday) in the northern hemisphere is at its highest on June 21 and its lowest on December 21. Correspondingly, the number of daylight hours available at the peak of summer is proportionally greater than the number of available daylight hours at the peak of winter. Solar radiation is the "resource" of solar energy and is measured in units of energy per unit time per unit area. The amount of solar energy available, like most energy resources, varies with location; however, unlike most other energy resources, solar energy availability also varies with time—for example, the season and the time of day. Environmental factors affect the average solar energy that the earth receives at any particular location or time.

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Availability of Solar Energy

The amount of solar radiation from the sun is a constant and, near the earth, is about 1,353 watts/square meter (W/m^2) on a surface perpendicular to the sun's rays. Because the earth's orbit is elliptical, however, this value varies about ± 3 percent; in the northern hemisphere, the highest value is in the winter and the lowest, in the summer.

As solar radiation passes through the atmosphere, it splits into direct, diffuse, and circumsolar radiation, as shown in Figure 10-1. Direct, or beam, radiation exhibits negligible direction change and scattering in the atmosphere. Diffuse solar radiation is radiation scattered by aerosols, dust, and clouds, and can best be understood by considering what a light coating of frost does to an automobile windshield. Without the frost, sunlight comes in from one direction. With frost, however, the entire windshield is illuminated, blocking vision in other directions; sunlight has been reflected and scattered across the windshield. If we were trying to collect sunlight through the clear windshield, the direct path of the sunlight would be our only concern; if, however, the sunlight were passing through the frosted windshield, only a small portion of the sunlight could be collected by focusing directly toward the sun, whereas much more could be collected by gathering in the diffuse light from the entire windshield. Clouds and haze in the atmosphere have similar effects on sunlight.

Circumsolar radiation, diffuse radiation parallel to the direct beam of sunlight, is the component of radiation that results from the broadening of the angular cone through which the sun's rays arrive. This broadening is caused by forward scattering in a turbid atmosphere containing large aerosols. Total or global radiation is the sum of diffuse and direct radiation.

Another form of solar radiation is that which comes up from the earth: radiation reflected from the ground (particularly from snow or water) and long wavelength infrared radiation released by warm ground temperatures to a cooler atmosphere. The reflected sunlight, known as albedo, may be an important factor in using solar heating in certain locations.

Temporal and Spatial Variations

As solar radiation passes through the atmosphere, 25 to 50 percent of the energy is lost by reflection, scattering, and absorption.[1] Even on a cloud-free day with unpolluted skies, about 30 percent of the incident energy (energy that enters the atmosphere) is lost and only 960 to 1,190 W/m^2 are available at the earth's surface.[2] If the sun shines 50 percent of the time (12 hours/day, every day) on a 1 m^2 surface, that surface receives no more than 4,200 to 5,200 kWh/year of solar energy. Since the sun actually shines less than 12 hours/day at any location, the maximum solar radiation a site can receive is about 2,550 kWh/m^2/year.[1]

Another way to illustrate atmospheric effects on solar radiation is to show solar energy distribution at different wavelengths (see Figure 10-2).[2] The reduction in energy shown in Figure 10-2 indicates the amount of energy scattered and absorbed by ozone, carbon dioxide, water vapor, and water droplets in the atmosphere as the incident energy travels to the earth's surface. Spectral distribution (variation of energy intensity with wavelength) is particularly important to solar technologies such as photovoltaics.

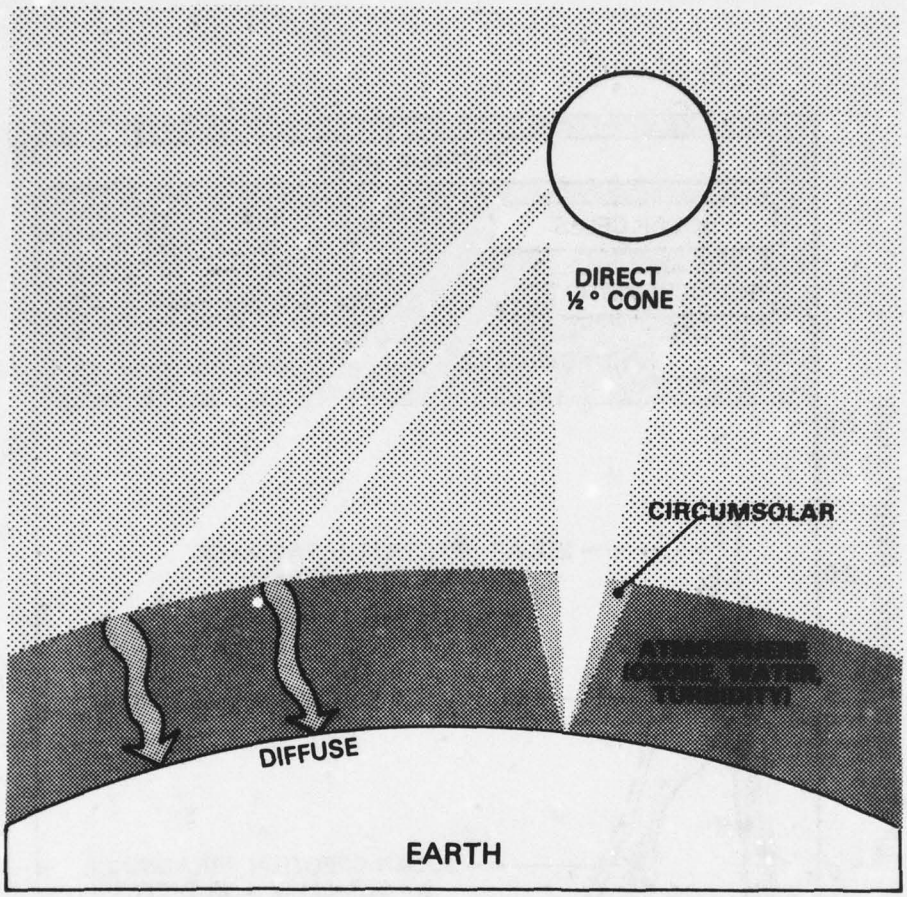
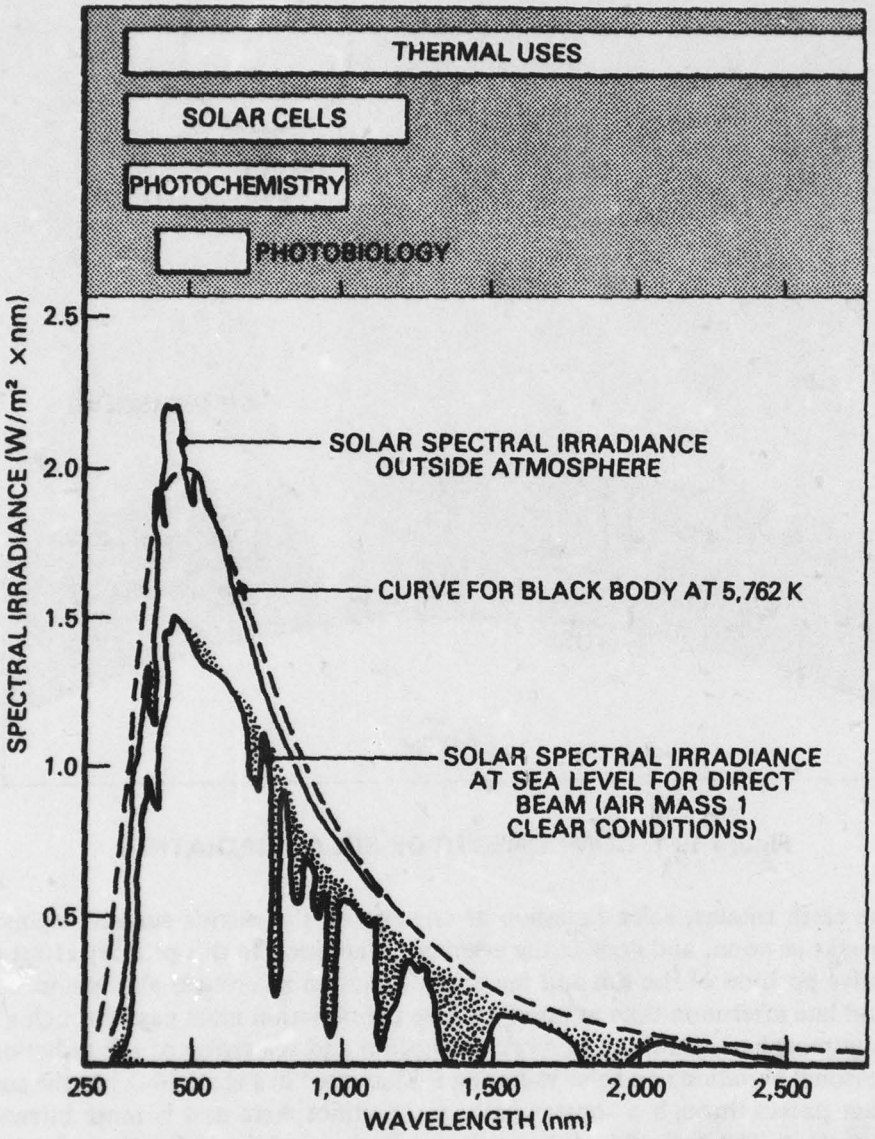


Figure 10-1. COMPONENTS OF SOLAR RADIATION

As the earth rotates, solar radiation at any site on the earth's surface begins in the morning, peaks at noon, and ends in the evening. In addition to this primary effect caused by the relative position of the sun and the earth, radiation received is also less in the early morning and late afternoon than at noon because the radiation must pass through a longer path in the atmosphere, resulting in more absorption and scattering of the radiation. The effect of seasonal variations on solar radiation is illustrated in Figure 10-3.[2] In the summer, the radiation passes through a shorter path in the atmosphere and is more intense on a horizontal surface. The radiation also lasts longer because of the inclination of the earth's axis.

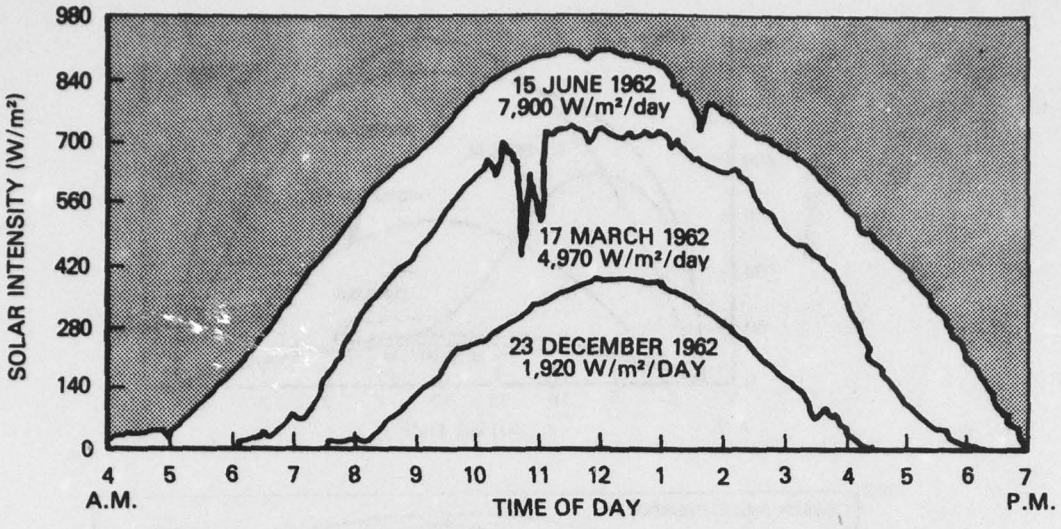
Cloud cover interferes with solar radiation and can affect appreciably the solar energy received; the solar intensity on mountaintops above the clouds normally would be greater than that in a neighboring valley, and a foggy location near the sea would receive diminished solar energy. Passing clouds that cover the sun and, thus, decrease the intensity of radiation reaching the earth's surface can reduce solar radiation by more than 90 percent from clear day intensities.[3] Air pollution also limits the amount of solar radiation received.



Note: Shaded areas indicate absorption due to atmospheric constituents, mainly water, carbon dioxide, and ozone. Wavelengths potentially utilized in different solar energy applications are indicated at the top of the figure.

Source: Frank Kreith and Jan Kreider, *Principles of Solar Engineering* (New York: McGraw-Hill Book Company, 1978).

Figure 10-2. SOLAR ENERGY DISTRIBUTION



Source: Frank Kreith and Jan Kreider, *Principles of Solar Engineering* (New York: McGraw-Hill Book Company, 1978).

Figure 10-3. TYPICAL SOLAR RADIATION ON CLEAR DAYS AT LATITUDE 43°N

Orientation of Receiving Surface

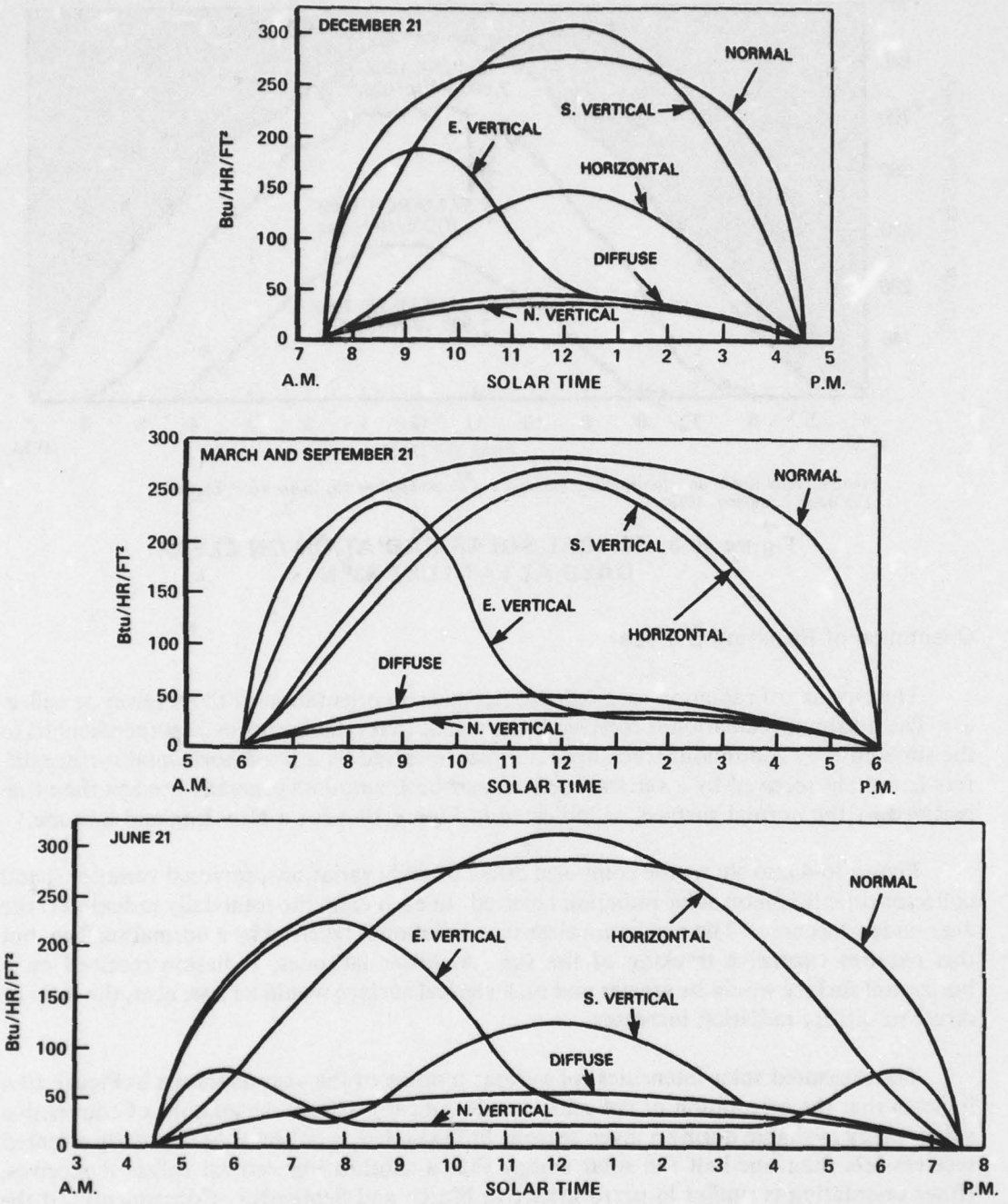
The amount of radiation received also depends on orientation of the receiver or collector. The maximum radiation is received by a surface that remains normal (perpendicular) to the sun's rays by continuous tracking. Radiation received by a fixed horizontal surface differs from that received by a vertical surface, and both amounts generally are less than that received by the normal surface, as indicated in Figure 10-4 for a New England latitude.[4]

Figure 10-4 also shows the combined effect of daily variations, seasonal variations, and collector orientation on solar radiation received. In each case, the total daily radiation is the area under the curve.[5] The maximum clear day radiation is received by a normal surface, but this requires expensive tracking of the sun. At lower latitudes, radiation received on a horizontal surface would be greater and on a vertical surface would be less; also, the ratio of direct to diffuse radiation increases.

The measured solar intensities for various months of the year as shown in Figure 10-4 indicate that the orientation of collector panels critically affects the amount of convertible solar energy available during a given season. In December, a collector horizontally oriented receives less than one-half the solar energy that a southfacing vertical collector receives; either orientation is similar in performance in March and September. Consequently, if the primary function of a solar collector is to provide heat for late fall, winter, and early spring months, then vertically oriented collectors would be more useful for New England latitudes.

Geographical Variations

The regions receiving the greatest amount of solar energy available for direct applica-



Source: I. F. Hand, U.S. Weather Bureau, January 1950.

Figure 10-4. INCIDENT SOLAR ENERGY ON CLEAR DAYS IN NEW ENGLAND, LATITUDE 42°N

tion are between 15° and 35° latitude on either side of the equator, as indicated in Figure 10-5.[2] The equatorial belt between 15°N and 15°S receives less solar energy than the tropical regions; the humidity is high, the clouds are frequent, and the proportion of scattered radiation is high. Between 35° and 45° latitude, radiation can average about 700 W/m² during the summer, but can drop significantly during the winter. Regions north of 45°N receive a limited amount of annual solar energy, especially in winter months. At these high latitudes, half the total annual solar radiation may be diffuse with a higher proportion of diffuse energy in the winter than in the summer; also, the maximum solar altitudes are low, particularly in winter. Consequently, at high latitudes, vertical surfaces facing the equator can receive greater amounts of solar energy than can horizontal surfaces. In Hamburg, West Germany, for example, solar radiation on a southfacing vertical surface can be over two and one-half times that falling on a horizontal surface.[4]

Geographical distribution of direct-normal and total horizontal solar radiation in the United States is mapped in Figures 10-6 and 10-7, respectively.[6] In using this type of map, qualifications must be considered, such as the orientation of the receiver, whether the radiation is a mean value, and whether the radiation is total or direct only. These maps usually represent only one orientation of receiving surface, which may not be the same orientation as the collector being considered.

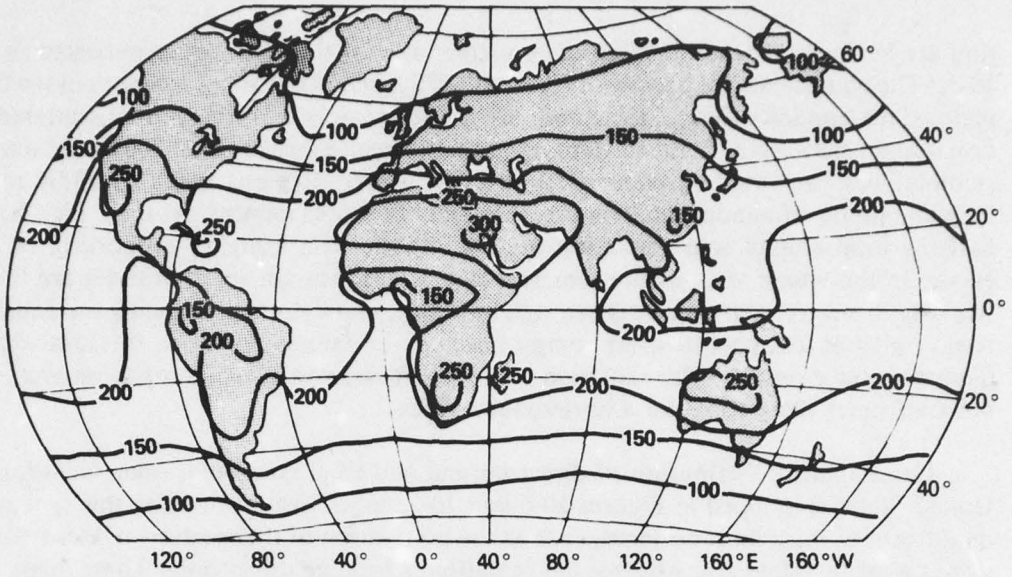
Solar Energy Measurement and Data Collection

About 700 stations in the world continuously record solar radiation intensity. These stations measure direct and scattered radiation on a horizontal surface, which is the basis of most available solar radiation charts. About 100 stations record radiation received on a surface maintained normal to the sun.

The Department of Energy (DOE), in cooperation with the National Oceanic and Atmospheric Administration, has established a network in the United States to measure direct, diffuse, and total solar radiation on an inclined surface. The primary purpose of this network is to give designers of solar systems an estimate of the available solar resource in particular locations. All new data are stored in SOLMET, a standard format for collecting and storing hourly solar radiation data. Other meteorological data, such as barometric pressure, temperature, wind velocity, and cloud cover, also are collected and stored in SOLMET.[3]

SOLAR HEATING AND COOLING

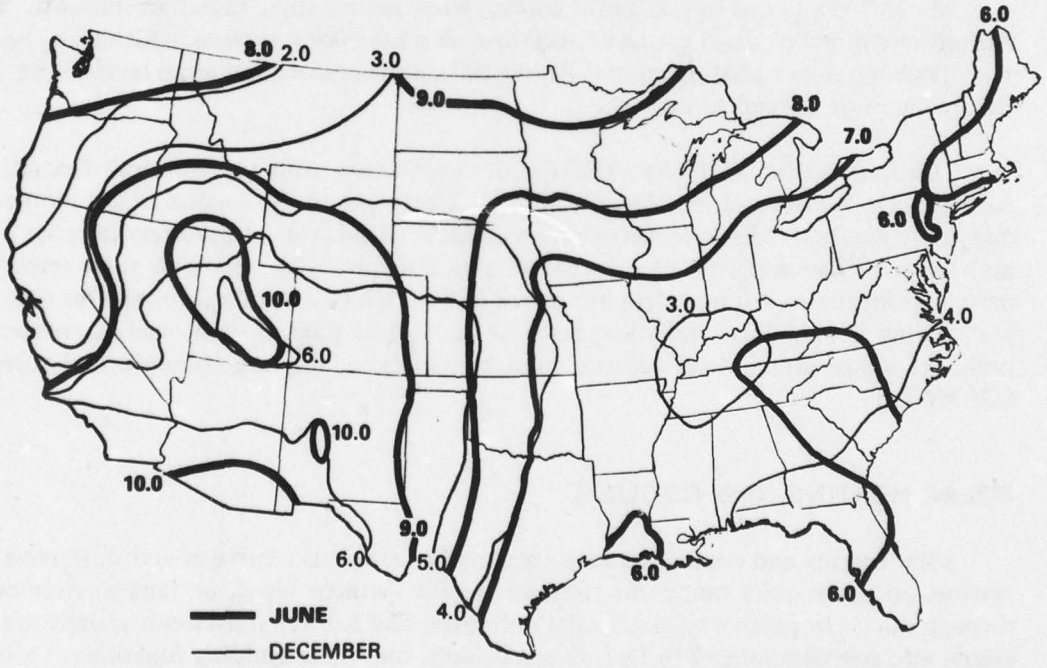
Solar heating and cooling systems are classified either as passive or active. Passive solar systems do not require pumps to circulate liquids through pipes, or fans to circulate air through ducts. In passive systems, solar collection and storage subsystems usually are integrated into one component; in fact, in some cases, the whole building functions as a live-in solar collector with built-in storage. Active solar heating and cooling systems circulate liquids or gases through pipes or other conduits to convey the necessary heat to where it can be used, and consist of other components to collect, store, and control the energy source. Designs that combine aspects of both active and passive systems are called hybrid systems.



Note: Numbers shown are W/m² averaged over 24 hours.

Source: Frank Kreith and Jan Kreider, *Principles of Solar Engineering* (New York: McGraw-Hill Book Company, 1978).

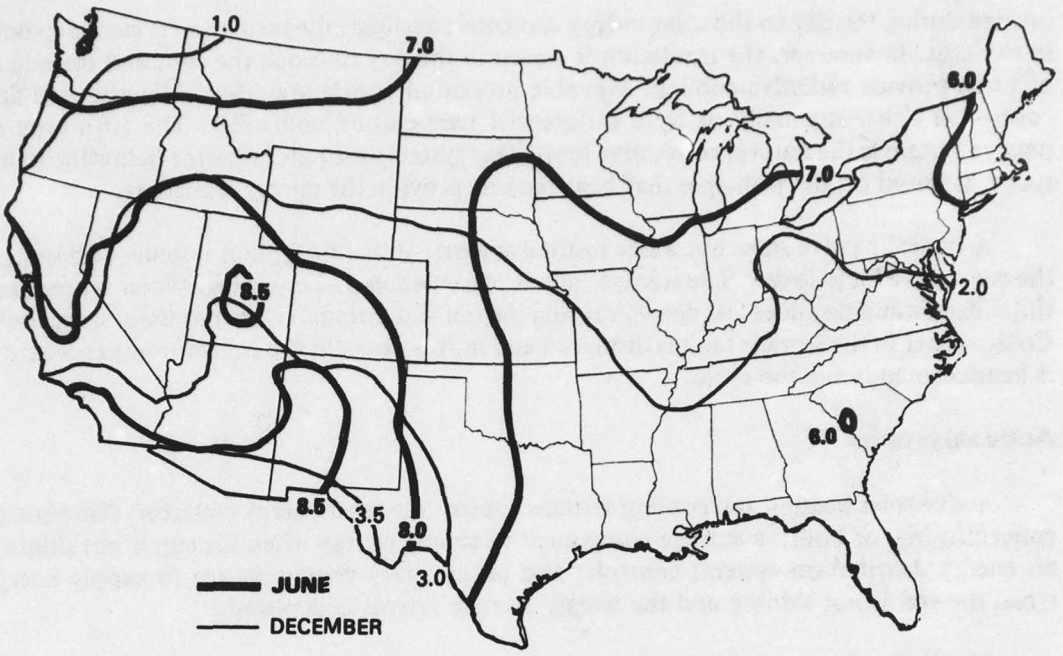
Figure 10-5. ANNUAL MEAN RADIATION ON A HORIZONTAL PLANE AT THE EARTH'S SURFACE



Note: Numbers are shown kWh/m².

Source: "Distribution of Direct and Total Solar Radiation Availabilities for the U.S.A.," SAND76-0411 Sandia Laboratories, 1976.

Figure 10-6. MEAN DAILY DIRECT-NORMAL SOLAR RADIATION



Note: Numbers shown are kWh/m².

Source: Sandia Laboratories, "Distribution of Direct and Total Solar Radiation Availabilities for the U.S.A.," SAND76-0411, 1976.

Figure 10-7. MEAN DAILY TOTAL HORIZONTAL SOLAR RADIATION

Solar heating systems are used primarily for hot water heating, space heating, and agricultural and industrial process heat applications. Solar cooling systems generally are combined with solar hot water and space heating systems to provide year-round use of the installed system.

Passive Systems

There are several types of passive system designs, including direct gain, thermal storage wall, solar greenhouse, roof pond, and convective loop. The simplest type of passive system is the direct gain design, which is simply an expanse of glass (usually double glazed) facing south (in the northern hemisphere). The collected energy is stored in the thermal mass of the floors and walls. A thermal storage wall system consists of a massive wall of a dark color behind southfacing double glazing. The wall may contain water or masonry (approximately 40 cm thick) to store the energy. A third type of passive system is the solar greenhouse (also known as a sunspace), which combines direct gain in the greenhouse and a thermal storage wall between the greenhouse and the house. Solar energy provides the heat for the greenhouse and a substantial amount of the energy for heating the living space in the house.

Another type of passive solar heating and cooling system is the roof pond, in which pillows of water act as the collector and thermal storage. Movable insulation (sliding polyurethane panels) is used to control the gain and loss of heat. In winter, the insulation is

opened during the day so the solar energy can enter; at night, the insulation is closed to hold in the heat. In summer, the insulation is closed in the day to block the sun, and opened at night to provide radiative cooling. Movable insulation panels are electrically powered and controlled either manually or by a differential temperature controller. The fifth type of passive system is the natural convective loop. This system, with the collector below the living space, is based on the principle that heat rises to provide the energy transport.

A typical passive solar hot water heating system—a thermosyphon system—is based on the convective loop design. The storage tank is placed above the collector. Water is heated in the collector and becomes less dense, causing the hot water to move up into the storage tank. Colder water in the storage tank is displaced and moves down to the collector intake where it is heated to continue the cycle.

Active Systems

Active solar heating and cooling systems consist of a solar energy collector, flat-plate or concentrating, or both; a storage component to supply energy when the sun is not shining; an energy distribution system; controls; and an auxiliary energy source to supply energy when the sun is not shining and the energy storage system is depleted.

A typical solar system design is depicted in Figure 10-8. In the system, a portion of the solar energy incident on the solar collector is transferred via a liquid heat transfer medium to the insulated thermal storage tank through the heat exchanger. (Other systems use air as the heat transfer medium.) The heat transfer liquid, which can be a nonfreezing solution or water, is returned to the collector in a closed loop and the process continues. The hot water from the storage tank is used to heat water in the hot water tank and is then returned to storage to be reheated. (In systems using air as the transfer medium, rock-bed storage is often used.) If the water temperature from the storage tank is too low or the water in the hot water tank is sufficiently warmed, the flow is cut off by a valve. If sufficient heat is not available from storage on demand, the auxiliary heater warms the water in the hot water tank. For space heating, the water from the storage tank is circulated through a water-to-air heat exchanger to warm air which is used for space heating. The water is then returned to the storage tank. If the temperature of the water coming from storage is not adequate to heat the house, supplemental heat is supplied to the water by the auxiliary heating unit prior to entering the water-to-air exchanger. If no heat is required for heating, the water flow is either diverted to the hot water tank or cut off completely by valves.

Active solar cooling systems are usually of the absorption, Rankine cycle, or desiccant types. These systems tend to be rather complex, and generally use solar heat to replace electrical energy as an input. Because of the relatively low temperature of the solar energy, however, measures of efficiency are fairly low. Higher temperature collectors are needed to gain reasonable cooling performance, and cooling towers usually are needed to lower the rejection temperature of these systems.

The absorption approach utilizes the affinity of various combinations of liquids to achieve virtual compression of a refrigerant. Following generation of the refrigerant vapor by solar heat input, the remainder of the cycle is similar to a standard vapor compression

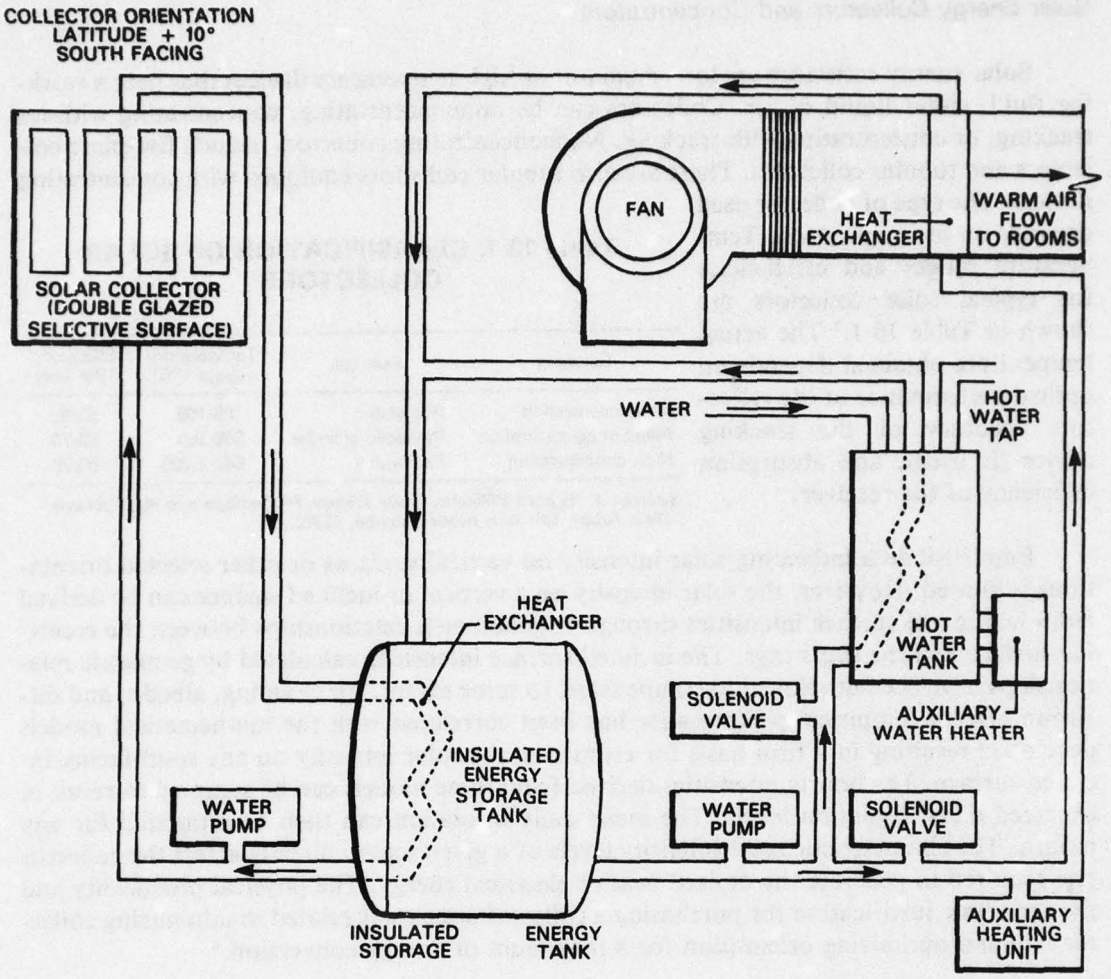


Figure 10-8. ACTIVE SOLAR WATER AND SPACE HEATING SYSTEM

cycle. The Rankine cooling cycle uses solar heat input to a heat engine to produce shaft power by expansion of the heated working fluid. The powered shaft is coupled with a conventional mechanical type vapor compression unit to achieve cooling. Desiccant systems use solid or liquid desiccant materials, which can be regenerated by solar heat. The devices provide a means of dehumidification and can be combined with partial rehumidification to achieve cooling.

A fourth approach, which has received very little attention to date, is the generation of electrical energy by solar cells, which is then used to power a conventional vapor compression unit. In addition to the solar cell array and heat pump, the system contains a power conditioning unit with a battery pack and other thermal storage and fluid transport components. The system would utilize available power from the electric utility during periods of low insolation.

Solar Energy Collectors and Concentrators

Solar energy collectors are low, medium, or high temperature devices that heat a working fluid, either liquid or air. Collectors can be nonconcentrating, concentrating without tracking, or concentrating with tracking. Nonconcentrating collectors include flat-plate collectors and tubular collectors. There are also tubular collectors equipped with concentrating devices. The type of collector used depends on the application. Temperature ranges and efficiencies for typical solar collectors are shown in Table 10-1.[7] The actual temperature obtained depends on optical performance of the reflector, accuracy of the tracking device (if used), and absorption efficiency of the receiver.

Table 10-1. CLASSIFICATION OF SOLAR COLLECTORS

Category	Example	Temperature Range (°C)	Efficiency (Percent)
No concentration	Flat plate	65-150	30-50
Medium concentration	Parabolic cylinder	260-650	50-70
High concentration	Parabodial	540-2,200	60-75

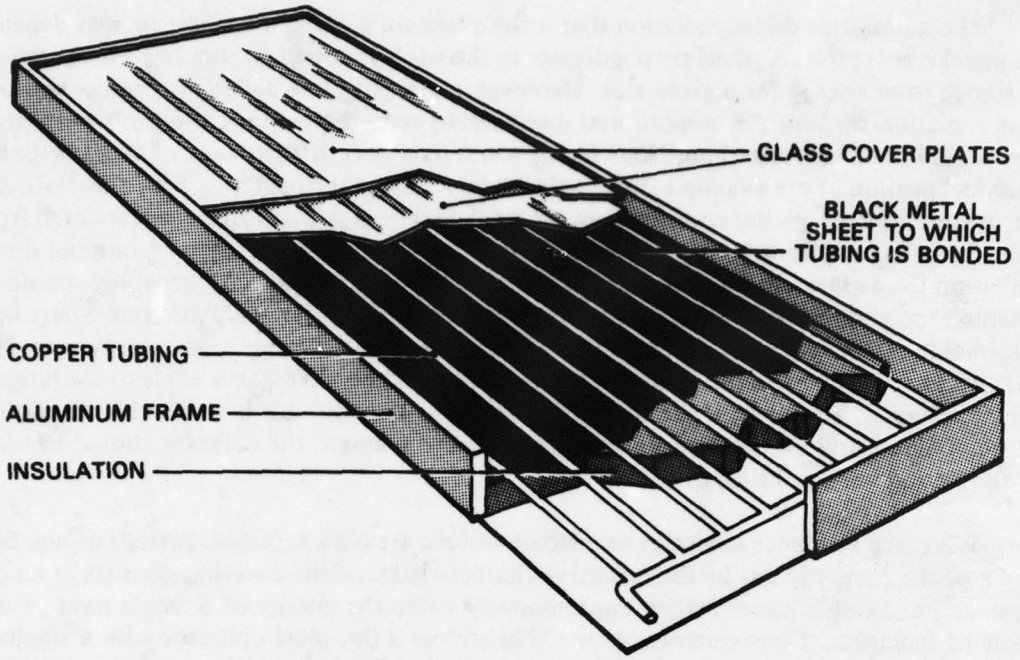
Source: J. Richard Williams, *Solar Energy Technology and Applications* (Ann Arbor, MI: Ann Arbor Science, 1975).

Empirical data indicating solar intensity on vertical surfaces or other selected orientations is limited. However, the solar intensity on a vertical or inclined surface can be derived from horizontal surface intensities through trigonometric relationships between the receiving surface and the sun's rays. The inclined surface intensities calculated by geometric relationships have been developed to compensate, to some extent, for clouding, albedo, and diffusion effects. Empirical performance has been correlated with the mathematical models developed resulting in a firm basis for estimating the solar intensity on any southfacing inclined surface. The hourly intensities derived from these models can be summed to result in expected daily insolation levels. The mean daily insolation can then be estimated for any month. The characteristic solar intensity levels of a given region directly affect the collector size required to generate the desired heat or electrical energy. The physical practicality and the economic justification for purchasing a collector are closely related to minimizing collector size and optimizing orientation for a maximum of energy conversion.[8]

Nonconcentrating Collectors

The simplest and most readily available type of solar energy collector is a large black surface that converts short wavelength solar radiation to long-wave heat radiation. The heat is conducted from the collector to air or water, which can then be used for space heating or for producing hot water.

A typical flat-plate collector is illustrated in Figure 10-9. A large flat plate of sheet metal is painted black (or has a selective surface) on the side that will face the sun. The working fluid circulates through tubing that is bonded to the sheet metal, and collects heat conducted from the plate. Generally, the tubing runs vertically, and is often integral with the absorber plate. The flat plate is enclosed in an airtight chamber, which is covered with at least one pane of clear glass (or plastic) so that short-wave solar radiation can pass easily through the transparent covering. The black surface tends to convert the short-wave solar radiation to long-wave infrared radiation, which is emitted from the black surface. The glass covering (a poor conductor of heat) traps the radiation and reduces heat loss from the flat-plate collector. Flat-plate collectors can produce water temperatures of 65 to 93°C under



Source: Daniel Levis, "SDHW Systems: What Experts Look For," *Solar Age,* IV, 2, February 1979.

Figure 10-9. FLAT-PLATE COLLECTOR

normal solar intensity, and temperatures approaching boiling are feasible on exceptionally hot days.

As solar radiation is converted by the flat-plate collector, a steady-state temperature is reached where the rates of heat recovery and loss are balanced by heat gain. Heat loss by convection to the surrounding air increases as wind velocity increases, particularly at high collector temperatures. Radiation losses also increase with the high collector temperatures. Transmission losses through the glass pane covers can be 15 to 20 percent. Between 80 and 95 percent of the solar energy passing through the glass pane covers can be absorbed. By using two or three layers of glass covering and insulating the panel, convection and conduction losses can be minimized. Evacuated tubes also can be used to reduce convective losses. Selective surfaces with emissivities as low as 0.15 have been developed; therefore, infrared radiation losses could be reduced to 15 percent of the heat absorbed. Using optimistic performance factors, an overall collector efficiency of 68.5 percent may be achievable. However, practical commercial designs, which keep material costs to a minimum, result in overall efficiencies less than 50 percent.[9]

The flat-plate collector can convert both diffuse solar energy, which is omnidirectional, and direct solar radiation. Meteorological data are available that distinguish the diffuse portion from the direct solar energy incident on a horizontal surface. In the northern latitudes, the diffuse energy can be a significant portion of the average solar energy available in winter months. Consequently, for flat-plate performance calculations, the diffuse energy for any region must be determined in calculating panel efficiency.

The amount of direct radiation that a flat-plate collector can convert to heat depends on panel orientation. A panel perpendicular to the sun's rays will accumulate the maximum available solar energy for a given size. However, since flat-plate collectors can convert diffuse radiation without the complicated mechanisms required to track the sun's path, they are usually fixed in inclined positions facing south to collect diffuse energy and a maximum practical portion of the available direct solar energy. Fixing the position of the flat-plate collector simplifies design but compromises the total daily energy that can be accumulated from solar radiation. Although mathematical models have been developed to determine direct radiation for a given orientation, a southfacing, fixed-position collector generally should be oriented for a compromise solar altitude that would convert solar energy to usable heat with reasonable effectiveness over as much of winter as practical. Where solar energy is to provide heat to a dwelling in the winter, the collector should be tilted at the angle of the latitude plus 15 degrees. However, if the primary function of the collector is to provide air cooling through an absorption air conditioning system in the summer, the collector should be tilted at the latitude minus 15 degrees.

When the incidence angles to a collector surface are high at certain periods of any day, much of the energy is lost by the reflective characteristics of the covering glass set at an oblique angle. Double panes reflect approximately twice the energy of a single pane at any angle of incidence. Consequently, where light strikes a flat-plate collector with a single or double glass cover at incident angles greater than 70 or 80 degrees, about 40 percent of the light energy is lost. During early morning and late evening hours, solar intensities are low. A southfacing collector will receive these weak solar energy levels at high incident angles. Therefore, much of the normal solar energy at the extreme hours of the day is lost. However, the normal energy component of the oblique rays can contribute cumulatively to the total daily solar energy that can be converted by a flat-plate collector. Orientation losses and transparent-covering reflection losses should be considered in estimating the daily energy accumulation performance of a given collector size.

The tubular solar collector is still in the developmental stage, but is expected to be commercially available soon. One type of tubular collector is composed of three concentric glass tubes, using manufacturing techniques similar to those for fluorescent light tubes (see Figure 10-10). The feeder tube is the innermost cylinder and is surrounded by the absorber tube. The outermost tube, a transparent cover, allows light to pass through an evacuated space to the absorber tube. (Some tubular collectors are not evacuated.) The absorber tube has a selective surface coating to absorb energy from the sun. The coating has a high absorptivity of solar radiation and a low emissivity of long-wave radiation, and may be constructed of thin deposits of oxides of nickel, chrome, and copper. Collector fluid flows in through the feeder tube, collecting heat from the selective surface of the absorber tube as it returns between the absorber and feeder tubes.

Because of its tubular construction, high vacuum (if so designed), and selective coating, the tubular collector can produce temperatures above 115 °C with greater efficiency than can flat-plate collectors. If the collector is equipped with a vacuum jacket, low ambient temperatures and high winds will have only minimal effects on tubular collector performance. Also, the tubular symmetry and low loss coefficient enable these collectors to heat fluids (air or water) to useful temperatures for longer periods of the day and under more diffuse conditions.

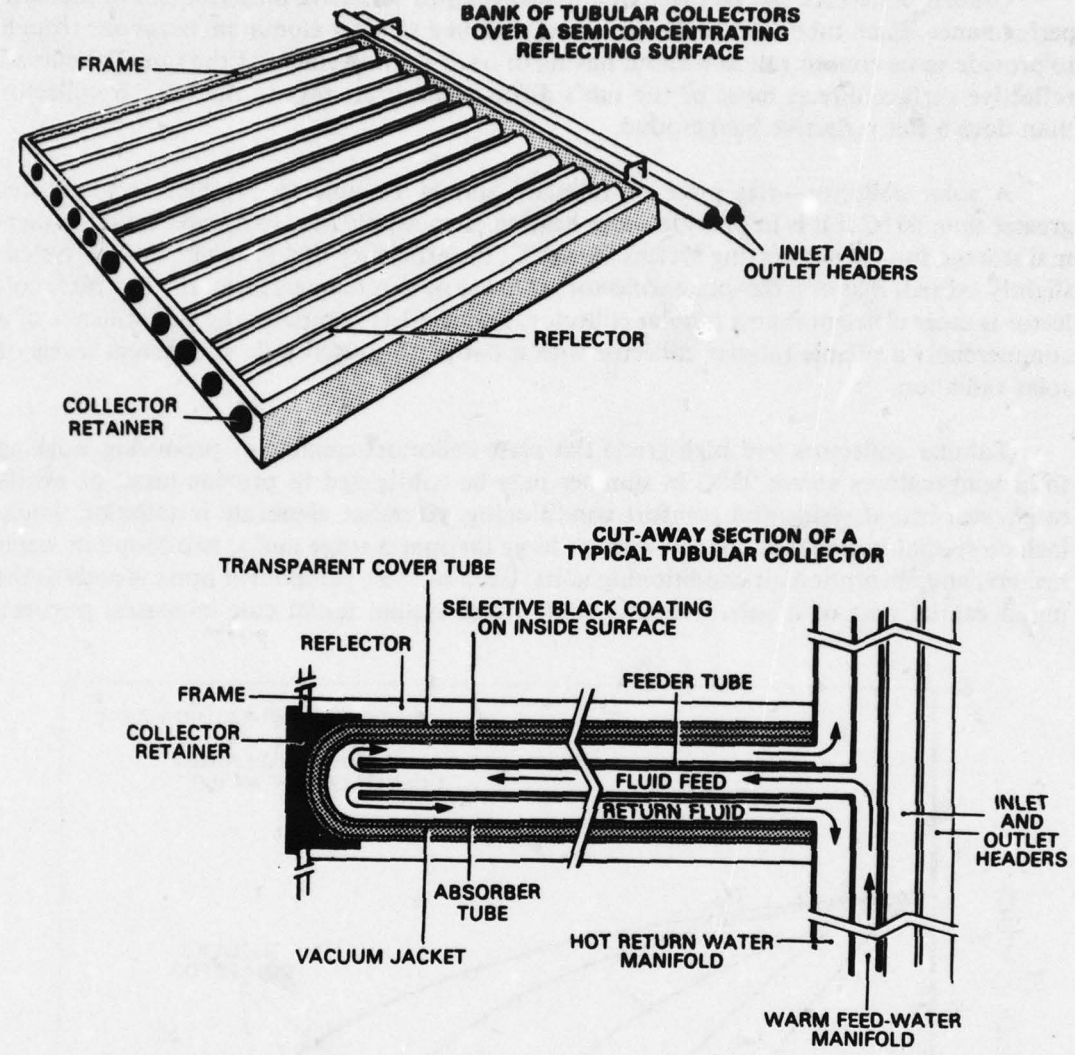
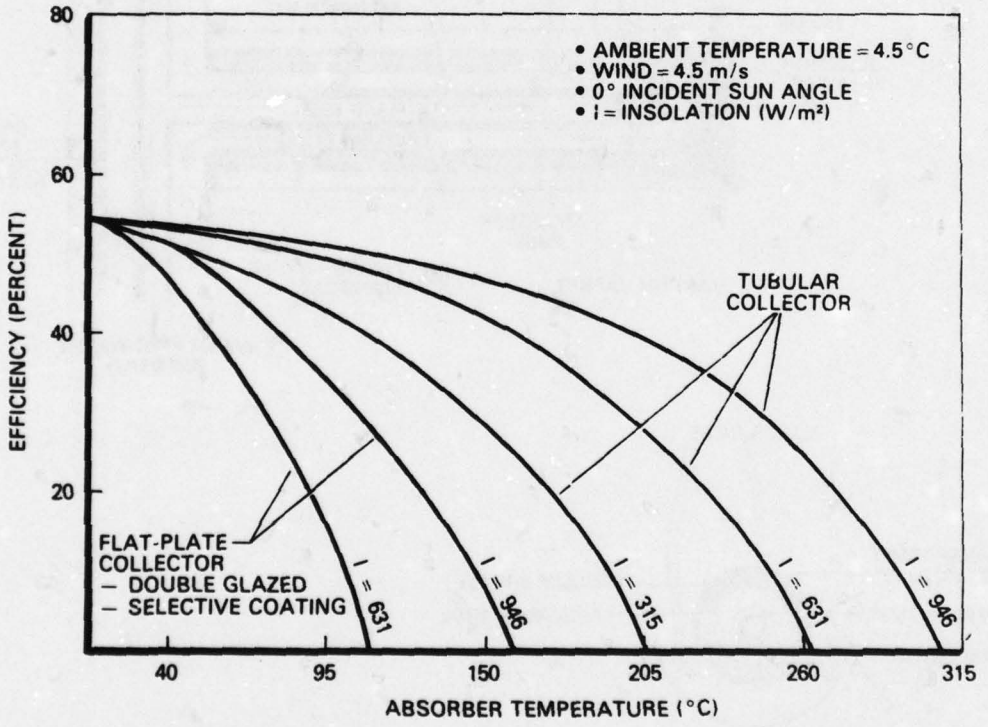


Figure 10-10. TUBULAR COLLECTOR

Tubular collectors can be placed on trough-shaped reflective backgrounds to increase performance. Each tube in the collector panel rests in a shallow aluminum parabolic trough to provide some concentration without having to track the movement of the sun. The curved reflective surface directs more of the sun's diffuse and direct rays to the tubular collector than does a flat reflective background.

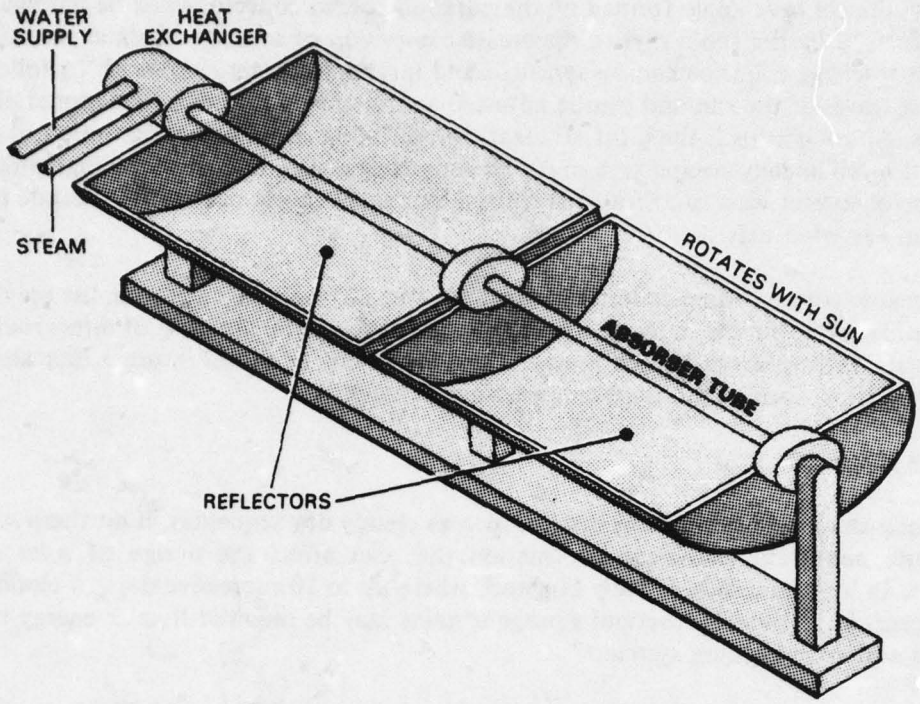
A solar collector—flat plate or tubular—should be able to produce temperatures greater than 60 °C if it is to provide water heating or to supply heat to a water tank for thermal storage for a space heating system. At 60 °C, the efficiency of a tubular collector system slightly exceeds that of a flat-plate collector; at lower output temperatures, the flat-plate collector is more efficient than a tubular collector. Figure 10-11 compares the performance of a commercially available tubular collector with a flat-plate collector given different levels of solar radiation.

Tubular collectors and high-grade flat-plate collectors capable of producing working fluid temperatures above 93 °C in summer may be configured to provide total, or nearly total, year-round residential comfort conditioning. A rather elaborate installation would include special system components such as large thermal storage tanks, two-loop hot water heaters, and absorption air conditioning units. Each of these component options adds to the initial capital cost of a solar system. As the total system initial cost increases, payback



Source: General Electric Company, Advanced Energy Programs/Space Division, "Solartron," Philadelphia, Pennsylvania, PIB-A-88, 1978.

Figure 10-11. COLLECTOR PERFORMANCE



Source: Frank Kreith and Jan Kreider, *Principles of Solar Engineering* (New York: McGraw-Hill Book Company, 1978).

Figure 10-12. TRACKING CONCENTRATOR COLLECTOR

periods may extend well beyond 10 years. Consequently, a high-grade solar conversion system may provide a large portion of winter space heating, summer cooling, and year-long water heating—possibly over 75 percent of a residence's total annual energy requirements, but the system may not pay for itself in fuel savings in less than 15 years.

Concentrating Collectors

A concentrating collector focuses the sun's energy on a relatively small area, creating high temperatures at the focal point. A typical concentrating collector is a parabolic prism reflector with a heat absorbing pipe at the focal point (see Figure 10-12). Water flowing through a collector pipe is heated to steam, which can be used to drive a turbine to produce power. Temperatures above 650°C can be generated by a parabolic collector. Other types of concentrating collectors utilize mirrors or lenses to produce the higher temperatures required for solar cooling and some industrial process heat.

A concentrating collector cannot convert diffuse energy and must continuously face the sun if high conversion efficiencies are to be maintained throughout the day. Ideally, the line

bisecting the concave angle formed by the parabolic prism collector must be parallel to all planes formed by the sun's rays to maximize conversion of available normal radiation. A two-axis tracking collector can be synchronized mechanically by clockwork to follow the east-west travel of the sun and can be adjusted automatically to the sun's seasonal altitude changes. Although this is the most efficient concentrating collector configuration, it is also the most mechanically complex. A practical compromise uses one-axis tracking, which will either pivot to east-west solar travel at a fixed inclination angle or pivot to altitude change about an east-west axis.

Because concentrating collectors cannot convert diffuse solar radiation, the use of concentrators may be limited to those areas that receive substantial amounts of direct radiation, such as the southwestern United States. They would not be useful in areas that are often cloudy or hazy, such as the northeastern United States.

Storage Systems

Long-range weather characteristics, such as cloudy day sequences in northern regions, constitute important statistical information that can affect the design of solar energy systems. In locations such as New England, where up to 10 successive days of cloud cover may occur, large-capacity thermal storage systems may be required if solar energy is to be used as a primary heating system.[4]

The flat-plate collector used for residential space heating (Figure 10-8) utilizes a storage system that provides a day or two of heating capacity to compensate for night-heating requirements and overcast conditions. Thermal storage systems may be either sensible heat or latent heat storage types. Sensible heat storage requires heating a material and causing a temperature rise, then releasing the accumulated heat as the material cools to ambient temperature. Water has the highest specific heat (4,200 J/kg°C) of any thermal storage material up to 90°C. Stone (5 to 10 cm diameter) is an inexpensive material commonly used for storing sensible heat and can have a heat capacity of 1,700 to 2,400 J/kg°C, about half the heat storage capacity of water.

Latent heat storage uses phase-change properties of various substances, including salt hydrates with heats of hydration in the range 30 to 50 kJ/kg, to store internal energy at temperature levels above or below ambient. For example, Glauber's salt ($Na_2SO_4 \cdot 10H_2O$) has high heat of fusion characteristics at a transition temperature of 32°C, with a heat capacity of 241 kJ/kg resulting from phase change; however, Glauber's salt cannot retain its heat for any practical length of time, and 24-hour storage of heat may not be feasible. The fundamental problem with salt hydrates is the deterioration of the freeze-thaw cycle repeatability. Also, hydration-dehydration materials tend to be more corrosive than materials with solid-solid or solid-liquid phase change properties as well as more expensive than water or rock used for storage up to about 130°C.

Controls

Electrical controls are used to regulate system operation. They are used to control energy flows in response to instantaneous values of temperature (or solar radiation) and

energy demands and to control pumps, diverting valves, load devices, backup systems, or collector tracking devices. For example, a differential thermostat usually is used to compare automatically the temperatures in different parts of the system. If the temperature is higher in the collector than in the storage unit by a set amount, the thermostat will turn on a pump to carry collector heat to storage. When the temperature is too low in both the collector and the storage tank, an auxiliary energy system is switched on. Proper operation of the controls and setting of the set points is critical for reliable, efficient operation of the solar energy system. The most frequently occurring technical problem in the DOE demonstration program has been with controls.[10]

Research and Development Programs

The federal R&D program for solar heating, cooling, and agricultural and industrial process heat consists of over 200 projects directed at improving performance of components and systems, improving manufacturing and analysis techniques, and lowering system costs. Emphasis is on solar cooling system cost-effectiveness, passive solar heating and cooling development, and solar retrofit cost reductions.

DOE has developed a program plan that pursues solar technology R&D in a directed manner, with a minimum of overlap and redundancy among funded projects. The main focus of the program is on specific approaches, or paths, to link methods of energy collection or rejection with particular applications. Eleven such paths have been identified for building applications and 11 for agricultural and industrial process heat applications. For example, there are two service hot water paths (liquid-heating collectors and air-heating collectors), and four space heating and five space cooling paths. To move along any of the paths, specific tasks must be undertaken. Approximately 360 tasks have been identified in five categories: collectors; storage and heat exchangers; chillers, air conditioners, and heat pumps; systems and controls; and nonengineering aspects.

Economics

About half the energy consumed by residential, commercial, and industrial users is in the form of hot air, hot water, or low-quality steam.[11] A very large portion of this domestic energy demand could be met by solar heating and cooling systems without particularly advanced development. Flat-plate collectors could produce up to 75 percent of the energy required for individual residential heating requirements. The primary disadvantage of solar heating panels is their cost. A one-floor house 9 by 9 m in a central U.S. location would require about 45 m^2 of collector area to provide 70 percent of winter water and space heating requirements. At higher output temperatures, the tubular collector can perform at much higher thermal efficiencies than a flat-plate collector. Tubular collectors appear to be more versatile than flat-plate collectors; they can perform as well for heating water in all seasons and yet produce the higher temperatures for efficient solar cooling in the summer. However, tubular collectors are relatively new and unproved. The cost of tubular collectors has been estimated at more than twice the cost of higher grade flat-plate collectors.

The cost of thermal storage systems is critical in the decision to adopt solar heating even when the cheapest materials are used. To meet average winter heating requirements of a

dwelling usually requires use of most of the roof area for solar collectors. In January and February, residential heating requirements are considerably higher than the average winter heating load, and solar intensity is at its lowest. The high heat demand and the low solar intensity of the two coldest months amplify the size requirements of solar panels required. Because roof-size limitations restrict the amount of heat that can be collected practically from solar radiation during the coldest months, very little or no reserve can be accumulated for overnight use. Solar heating must be supplemented with an electrical or fossil-fuel fired home heating system during exceptional demand. With the requirement for an auxiliary heating system, it becomes difficult to justify the capital investment for a thermal storage system with a capacity greater than the average overnight heating demand. Practical solar heating systems are sized for compromise conditions to accumulate possibly up to 24 hours of reserve heat during "average" winter heating and solar intensity months. A tank of 4.6 m^3 of water elevated 38 °C in temperature may be able to provide one day of reserve heat for a typical house. This $1 \times 2 \times 2.4$ m tank would require a large closet in a basement.[11]

Because of the higher initial cost of solar energy systems, the value of the energy saved over the life of the system must be considered. The economics of a solar energy system versus those of a conventional system can be determined only by analyzing life-cycle costs. Typical costs for 1978 and projected costs for 1985 for active solar residential heating and combined water and space heating systems are shown in Table 10-2.[12] (Costs do not reflect any existing or proposed incentives for solar energy conversion.) Passive systems presently add $2,500 to $8,000 to the building cost for space heating, but simpler, standardized systems are expected to reduce these costs significantly.[13] Solar energy is competitive today for water heating applications when compared to electricity as the alternative; at present, combined solar water and space heating for detached residences is marginally competitive against electricity.[14] As can be seen in Table 10-2, the real cost of installed solar water and space heating systems is expected to be reduced by about 25 percent by 1985. This cost reduction is expected to be achieved through continued research and development.[14]

Table 10-2. RESIDENTIAL SOLAR APPLICATIONS[a]

Component	Hot Water		Hot Water and Space Heating	
	1978	1985	1978	1985
Collector cost ($/ft²)	15-30	8-20	15-30	8-20
Collector size (ft²)	50	50	300-400	200-400
Total system cost (1978 dollars) (Solar provides 50 to 80 percent of total energy)	1,600-2,500 (32-50/ft²)	1,000-1,500 (20-30/ft²)	8,100-13,200 (27-33/ft²)	4,000-10,000 (20-25/ft²)

[a]Commercially installed.

Source: U.S. Department of Energy, "Solar Energy, A Status Report," DOE/ET-0062, June 1978.

The initial cost of a hot water system is about $800 to $1,500 uninstalled.[15] Installation costs vary greatly. Typically, installation of a residential hot water system in the Washington, D.C., area costs about $2,200. Solar water heating is cost competitive when compared with

electricity in most parts of the United States. The primary reason for its favorable economics is that the hot water load is fairly constant throughout the year, resulting in a favorable load factor. In addition, the system is fairly simple, so that the installed cost/ft² of solar collector is fairly low.[16]

Total installed cost/ft² of collector in 1978 dollars is $32 to $50 for hot water, and $27 to $33 for hot water and space heating. Solar space heating systems tend to cost more than hot water heating systems because of storage requirements, more complex controls, and other factors. Furthermore, the space heating load varies throughout the year from zero in the summer to maximum in winter. If cooling is not included in the system, this means that expensive equipment is sitting idle all summer (except for providing hot water). It usually is not economical to try to provide 100 percent of the heat from solar energy. Like most solar systems, space heating systems are sized to provide only about 50 to 75 percent of the load and an auxiliary heating system is required. Solar heating installed costs are now about $25 to $50/ft² so that a residential system costs over $10,000.[16] Because solar cooling is still in the developmental stage, not much is known about residential systems cost. However, the systems are complex, and their cost at present is too high to compete with conventional systems. For example, a residential 3 ton solar air conditioning system costs $22,000 to $26,000, or about 10 times the cost of a conventional system.[13]

The economics of solar energy are distorted by federal and state taxing policy and pricing policies for natural gas, fuel oil, and electricity.[14] In partial compensation for subsidies for conventional fuels, the National Energy Act passed by Congress includes tax credits for solar energy systems for residential use (P.L. 95-618). A taxpayer could receive up to 30 percent of the first $2,000 spent and 20 percent on the next $8,000 spent on qualifying equipment, a maximum tax credit of $2,200. The tax credit tends to make solar hot water and space heating competitive with electricity, but not with oil and gas.

In view of estimates that existing houses will provide approximately 50 percent of the housing needs in 2000, newly constructed solar homes will probably not be able to contribute significantly to residential or building heating requirements for the near future.[17] However, many houses may be able to retrofit modular systems on existing roof surfaces. Panels of limited size could be installed on roofs or elsewhere on the property to provide 25 to 30 percent of winter heating requirements. If the scope of supplemental heating were kept within these limits, a home could be heated while the sun shines and no thermal storage system would need to be incorporated. With this approach, at least daytime heating requirements could be offset to some extent. The overall effect could be a significant reduction in annual heating requirements and costs by the individual homeowner. The initial capital cost of a limited-size panel then may be justified over a long-term fuel cost savings. As the cost of fuel for heating increases, individual houses, schools, commercial buildings, and factories may convert to limited solar heating to offset conventional fuel requirements. Several relatively portable units, some containing limited thermal storage, are currently being sold. Various commercial units are being introduced for residential application.

SOLAR THERMAL POWER SYSTEMS

Solar thermal power systems convert solar energy into electricity, using various types of

solar collectors to collect light energy and convert it to heat. The heat is used to produce steam or other gases, which drive turbines and generators to produce electricity. This system is distinguished from conventional fossil-fuel fired power plants only by using solar energy to heat the boiler. This use of existing power generating technology may result in relatively near-term commercial applications. Future development of second or third generation systems will use nonconventional technologies.

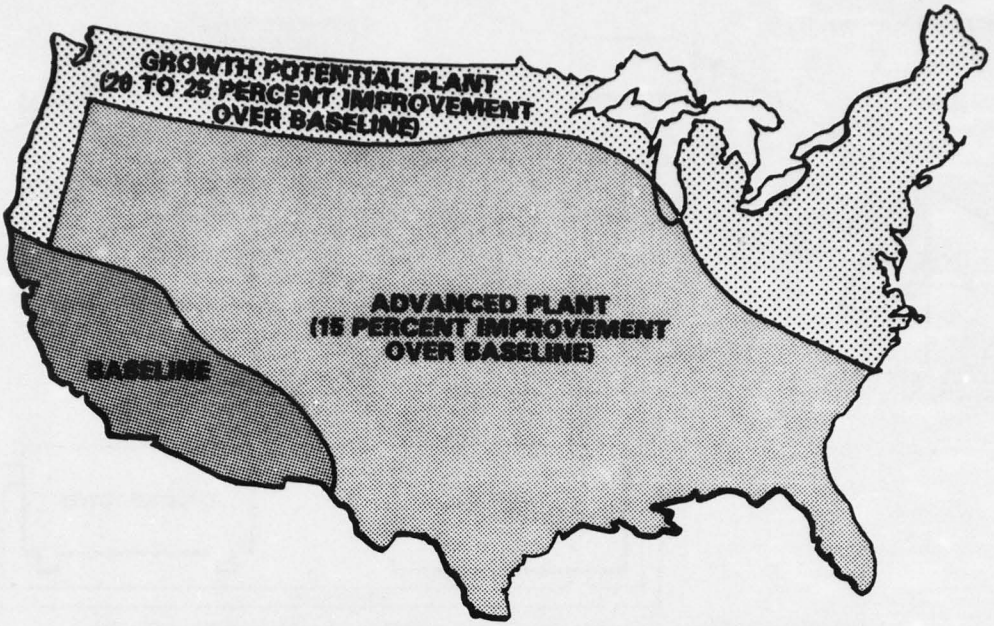
Solar power plant systems using concentrating collectors could be used to farm a large area of solar energy to produce the quantity of steam required to drive a major electric utility. These power plants could be set up as banks of parabolic concentrators over large areas, or as a tower collector, using flat reflectors to direct sunlight to a central collector where the solar energy is further concentrated to produce the high-cycle temperatures required of an efficient thermal power plant. These solar farms would require large land areas to provide central-station power levels. A 1,000 MW continuous-duty power station would require a collector area of 16 km^2, assuming a steam system efficiency of 25 percent. However, banks of collectors on a solar farm will tend to shade each other during early morning and late evening hours when solar incident angles are oblique. Consequently, if full collector utilization is to occur at solar altitude angles of 30 degrees or more, collectors will have to be spaced at least one panel apart. As a result, the land area required can be double the collector area required if collector effectiveness is to be maximized for full-day solar energy conversion. The 1,000 MW power station would therefore require approximately 32 km^2. The reflectors of a tower top concentrating system are subject to the same spacing and plan area requirements of parabolic collectors.[9]

Solar thermal technology is expected to first penetrate utility and dispersed applications markets in the southwestern United States where sunlight conditions are optimal. Expanded market penetration beyond the southwest is expected to follow based on anticipated cost reductions and performance improvements resulting from the development of advanced technology.[12] Geographical applicability is depicted in Figure 10-13.

A solar thermal power system comprises collectors/concentrators, a receiver/heat transfer tower, high-temperature storage, backup power, electrical power generator, and a heat rejection unit (cooling tower) (see Figure 10-14). In total energy systems, there is also a low temperature storage subsystem and a thermal distribution subsystem. The two major collection technology concepts in solar thermal power systems are the central receiver and the distributed receiver.

Central Receiver Systems

A central receiver system collects and concentrates solar radiation onto a central receiver using a field of heliostats (dual-axis tracking mirrors). The heliostats track the east-west movement of the sun and are automatically adjusted to the sun's seasonal altitude variations, thus maintaining continuous focus on the central receiver mounted on top of the tower (see Figure 10-14). These collectors/concentrators attain temperatures exceeding 540°C, resulting in overall conversion efficiencies of approximately 24 percent for the central receiver/heat transfer unit.[18]



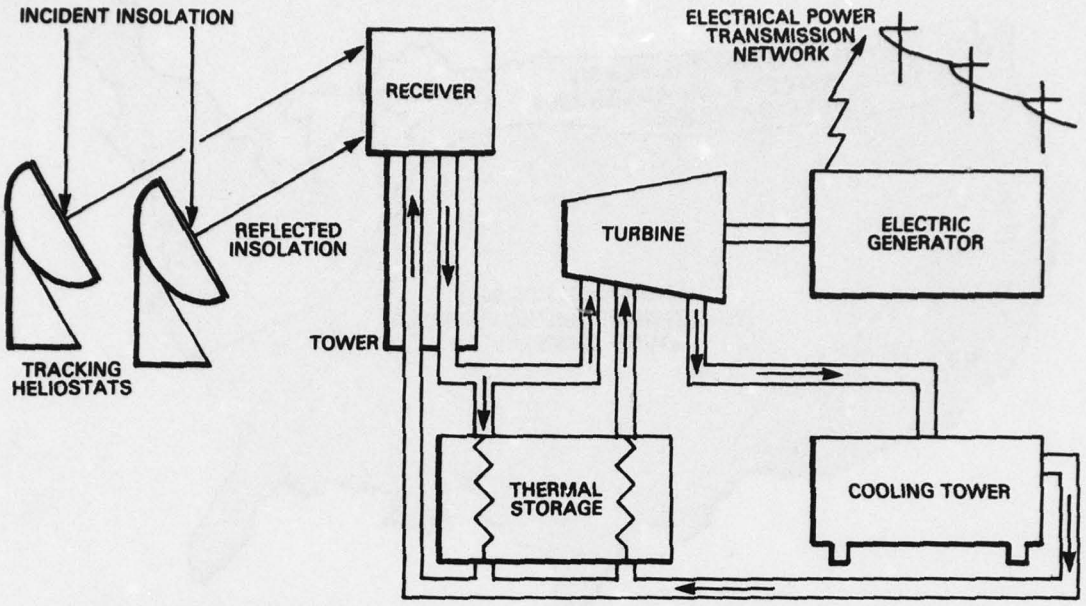
Note: Baseline represents the needed development status for practical application of solar thermal systems in the most desirable source conditions. Improvement over baseline refers to the additional amount of technology development (cost reduction) needed before practical application would be possible in the designated geographical areas.

Source: U.S. Department of Energy, "Solar, Geothermal, Electric and Storage Systems Program Summary Document," DOE/ET-0041(78), March 1978.

Figure 10-13. GEOGRAPHICAL APPLICABILITY OF SOLAR THERMAL SYSTEMS

The receiver/heat transfer unit collects the redirected solar radiation from the heliostats and transfers the solar energy to a working fluid. The heated fluid, used directly or indirectly, powers a turbine through a boiler or heat exchanger to generate electric power. Commercial receiver towers may be 245 to 470 m in height, and constructed of steel or concrete. Two basic designs of receiver units are presently under development, including the externally heated (planar) receiver and the cavity type. In the external heated configuration, the outer surface is at the focus of the heliostats to absorb the radiant energy. It is subject to losses of radiation and convection heat to the atmosphere. The cavity receiver concept counters this heat loss by enclosing the receiver in heavily insulated walls, limiting heat loss to that through the aperture. Examples of receiver concepts are shown in Figure 10-15.

Thermal energy from the receiver/heat transfer subsystem is converted into electric power through the use of a steam or gas turbine. The two basic systems being investigated are the steam Rankine cycle, which is the system used in conventional steam electric plants today, and the Brayton gas turbine cycle, which uses a gas as the working fluid, either in an open or closed cycle. (An example of an open Brayton cycle is the aircraft jet engine.) Although gases do not transfer heat as well as do liquids, the Brayton cycle will result in higher temperature and higher efficiency systems than will the Rankine cycle.[19] The steam Rankine cycle would require a considerable amount of cooling water, but the Brayton cycle would require little or no cooling.[20]



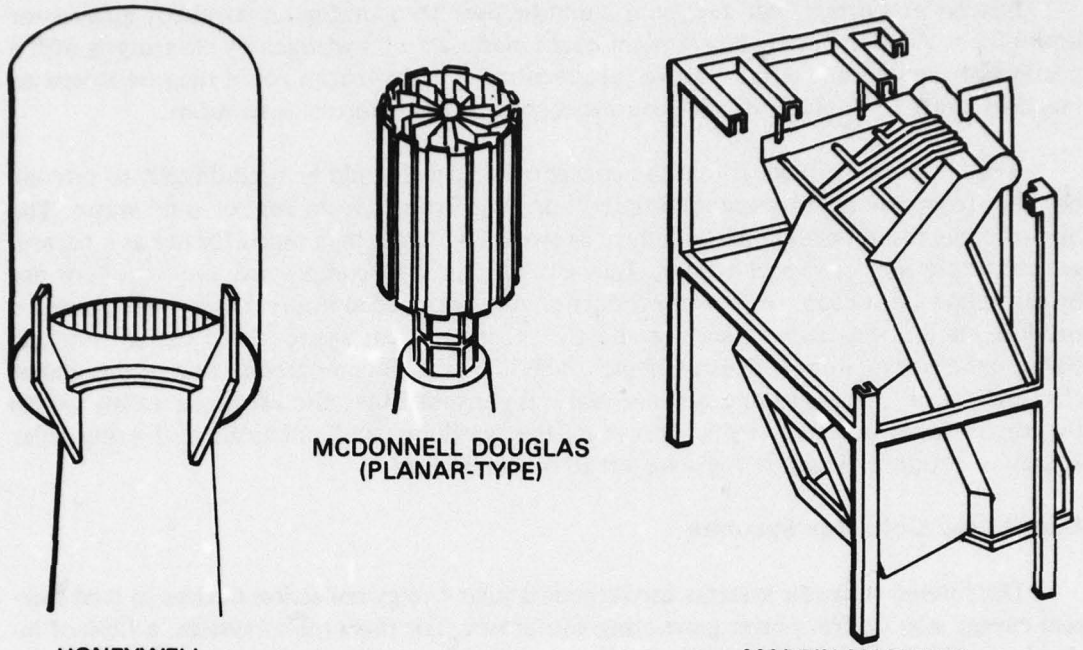
Source: U.S. Department of Energy, "Environmental Development Plan, Solar Thermal Power Systems," DOE/EDP-0004, March 1978.

Figure 10-14. CENTRAL RECEIVER SOLAR THERMAL POWER SYSTEM

Energy storage systems used with collector/concentrator power plants are similar to those described for flat-plate collectors. The thermal storage unit stores thermal energy generated by the collector and receiver systems for times when direct solar radiation is not available, using either sensible heat transfer or latent heat of fusion principles. Sensible heat transfer involves the specific heat properties of materials such as rock and oils. Latent heat of fusion involves phase changes (for example, freezing and thawing of materials such as eutectic salts). Storage systems need to be capable of storing thermal energy at temperatures of about 600 °C, since efficient steam turbine generation systems require steam at 600 °C.[11]

Scrap iron and magnetite (iron ore) are sensible heat storage materials capable of storing thermal energy at these high temperatures; however, using these materials to store heat for a solar thermal electric power plant does not appear practical for even the simplest application. (To generate 100 MWh of electric energy would require 6,441 metric tons of iron and an iron thermal storage tank volume of 1,444 m^3 (51,000 ft^3).)

Lithium hydride, a latent heat storage material with a heat of fusion of 3.25 million Btu/m^3, changes phase from solid to liquid at 650 to 700 °C. With this form of heat storage, a storage tank volume of about 310 m^3 is required to generate 100 MWh of electric energy. In cubic form, this tank would be about 6.7 m on each side and weigh about 27 metric tons. Although this tank would be much smaller and lighter than an iron thermal storage tank with comparable heat storage capacity, lithium hydride thermal storage would still require enormous volumes for large solar thermal electric power plants. Also, lithium hydride is more costly than other thermal storage materials and poses engineering problems in transferring the heat of the phase change as the molten lithium hydride crystallizes. Latent heat storage does not appear practical for a solar thermal electric power plant.



Source: Office of Technology Assessment, "Application of Solar Technology to Today's Energy Needs," June 1978.

Figure 10-15. RECEIVER CONCEPTS

Electrochemical storage appears to be a more direct method of storing electric energy for solar electric power stations. Several advanced battery concepts are being developed, having specific energy capacities of 200 Wh/lb.[11] A 1 MWh energy demand would require advanced batteries weighing 5,000 lb. Lead-acid batteries would weigh 10 times as much as advanced batteries for the same energy demand. The cost of the materials for advanced batteries prohibits their practical consideration. Even though the cost per unit weight of conventional batteries may be relatively low, the greater quantities that would be required for storing comparable energy levels would also result in high costs. Therefore, batteries do not appear practical for storing the large quantities of energy required by a central power station.

Rock or molten salt thermal storage systems for solar electric power plants have been suggested, however, this type of thermal storage would produce steam at only about 100 to 200°C.[9] Much larger conventional turbines would be required to use the low-energy steam that would be produced at these temperatures. A plant operating with a maximum steam temperature of 150°C would have a thermal efficiency half that of a conventional plant using steam at 540°C. The inefficiency of a low-energy steam cycle would further amplify the size of the turbines required. The initial capital cost of a low-energy steam plant would be considerably higher than conventional power machinery. Although a rock or molten salt thermal storage system could be designed, such a system would not be practical or feasible for central power stations.

Instead of storing solar energy, it could be used to manufacture synthetic gaseous or liquid fuels. A solar electric power plant could manufacture hydrogen by electrolysis with a portion of the daytime electric power production.[9] The hydrogen could then be stored as metal hydrides to be used as a fuel during nighttime and overcast operations.

Yet another possibility is that the concentrator panel could be used directly to provide the high temperatures to manufacture low- or high-Btu gas from coal or solid waste. The high-Btu gas could be liquefied to reduce its storage volume, then piped for use as a natural gas substitute for residential heating. Low-Btu gas could be compressed and stored for use by central power stations for power production during off-solar hours. Using solar energy to produce natural gas substitutes may be the most practical approach to energy storage, because the energy storage density of such fuels is very high compared to that of thermal or electrochemical energy storage systems. Natural gas substitutes also are more readily usable by conventional power systems. However, the feasibility and practicality of using solar energy to produce synthetic fuels are yet to be determined.

Distributed Collector Systems

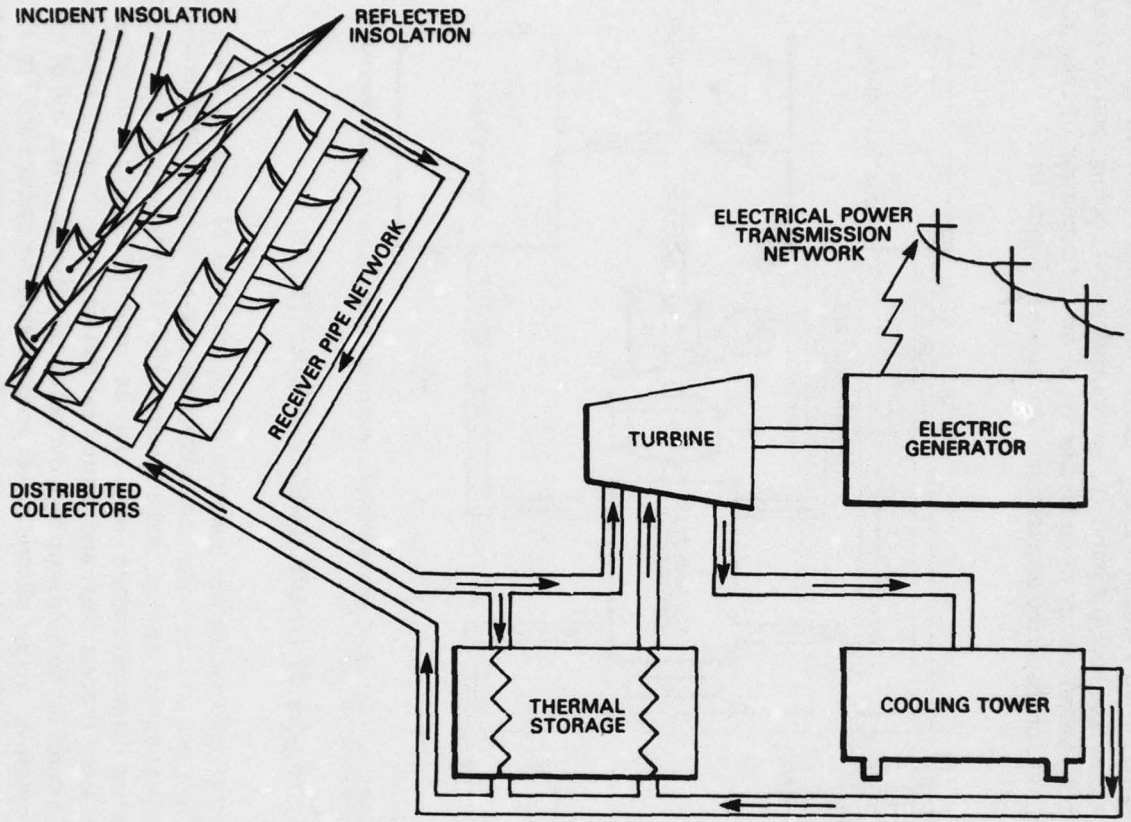
Distributed collector systems use dispersed solar energy collection devices to feed thermal energy into central power generating equipment. For this type of system, a field of individual collectors concentrates the sun's rays onto a network of receiver pipes (see Figure 10-16). These systems also must track the sun across the sky, and can make use of only the direct component of solar radiation. The two basic distributed collector system receiver designs are point focusing and line focusing. The parabolic dish focuses on an absorber at the focal point of the dish and is capable of generating temperatures of approximately 800°C. Systems using the parabolic dish receiver generally have overall conversion efficiencies of 20 to 25 percent.[18]

An example of a line focusing concept is the parabolic trough collector, which focuses the sun's rays on a long receiver tube. Another example is the fixed (segmented) mirror concentrator, in which the absorber, rather than the collector, is moved to track the sun. Line focusing collectors generally are designed to operate at about 300°C. Secondary concentrators could increase these operating temperatures to about 500°C. At these temperatures, overall conversion efficiencies range from 12 to 18 percent.[18]

Applications

Three major conceptual applications of the solar thermal power program are in large-scale centralized electric power generation; smaller-scale dispersed applications for electric power generation; and smaller-scale on-site total energy applications involving both electricity and heat production. Central power applications focus on large solar thermal plants ranging from 10 to 300 MW. These large plants are perceived as forming an integral part of existing electric utility networks as either large (50 to 300 MW) new power plants or retrofit systems for repowering smaller (10 to 100 MW) older power plants now fueled with natural gas or imported oil.[21]

Large solar thermal power plants will include energy storage facilities, while solar

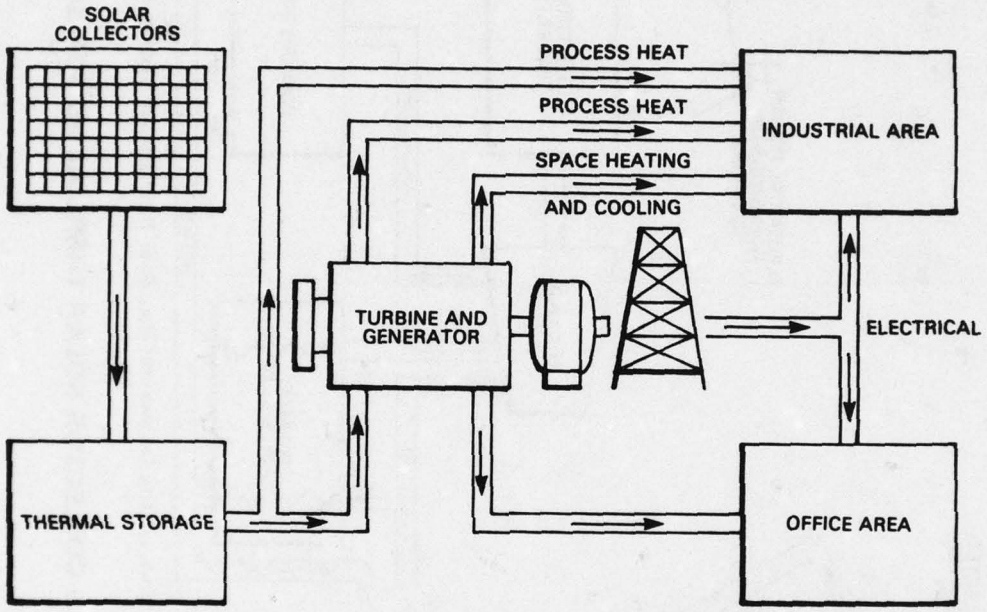


Source: U.S. Department of Energy, "Environmental Development Plan, Solar Thermal Power Systems," DOE/EDP-0004, March 1978.

Figure 10-16. DISTRIBUTED COLLECTOR SOLAR THERMAL POWER SYSTEM

repowering of existing fossil-fueled plants will not. Another concept of central power application, known as the solar/fossil hybrid system, is to build a new solar plant with storage in the form of fuel rather than thermal energy.

Dispersed power and total energy applications include small community systems, irrigation pumping, and remote operations. These installations are generally less than 50 MW and are closer to the user, usually within 5 km.[22] The thermal energy generated by the solar system can be used as process heat for industry, space heating and cooling, and hot water converted to direct mechanical energy or to electricity, or any combination of these uses. Potential configurations for dispersed applications are shown in Figure 10-17.



Source: U.S. Department of Energy, "Solar, Geothermal, Electric and Storage Systems Program Summary Document," DOE/ET-0041(78), March 1978.

Figure 10-17. DISPERSED APPLICATIONS

Solar total energy systems include concepts of cogeneration of steam or electricity. Electricity can be generated and the waste heat utilized for low- or intermediate-temperature process heat, space heating and cooling, and hot water. High-temperature process heat can be produced, intermediate-temperature heat can be used to produce electricity or intermediate-temperature process heat, and waste heat can be used for space heating and cooling. All of these concepts demonstrate high overall system efficiency because of the use of waste heat. For example, average electric power generation cycles operate at 25 to 35 percent efficiency, whereas a total energy system is capable of overall energy utilization (electrical plus thermal) in the 60 to 70 percent range.[18]

Remote applications, as defined by DOE, now emphasize irrigation pumping applications (under 500 kW). Collected solar energy heats a working fluid which drives a heat engine, producing mechanical energy to drive the pumps directly, or is converted to electricity, which in turn drives the pump motor.

Research and Development Programs

Numerous federal and private R&D projects on solar thermal power systems are presently in progress in the United States and other parts of the world. Since determining the technical feasibility of solar thermal power systems, the U.S. federal R&D effort currently focuses on providing for commercial implementation of dispersed thermal power systems by the early 1980s, and establishing solar thermal power as a technically, economically, and environmentally acceptable generation resource for electric utility applications by the mid-1980s.[21] The program consists of three parts, including large power system applications, small power system applications, and advanced thermal technology. Small power applications include total energy systems, small community systems, and remote systems (irrigation).

The thrust of the current DOE program is toward applications with a potential for early market penetration. A 5 MW solar thermal test facility has been completed at Sandia Laboratories near Albuquerque, New Mexico, for $21 million. It can be used to test and evaluate all major subsystems and components including receivers, heliostats, and high-temperature thermal storage systems. Detailed engineering design has been initiated on a 10 MWe central receiver experimental module that is scheduled for operation in a utility grid in Barstow, California, in 1981. This plant will be jointly funded by DOE, the Southern California Edison Company, and the Los Angeles Department of Water and Power at a cost of about $130 million.[22] The system will use 2,000 heliostats.

A total energy test facility at the Sandia Laboratories is now operational. Its purpose is to evaluate subsystem component designs under different operating conditions. Other testing of total energy systems at Shenandoah, Georgia, is scheduled for completion in September 1980.[12]

A shallow-well irrigation pump using solar thermal power has been successfully operating in Willard, New Mexico, for a year, and has been expanded to 50 HP capacity. The pump system uses a distributed solar energy collector system to heat a working fluid used to evaporate Freon in a heat exchanger. The organic vapors drive a turbine and the connected pump. Construction also has begun on a 200 HP deep-well experiment at Coolidge, Arizona.[23]

Economics

Since solar thermal power systems are still in the developmental stage, the economics are not well-established. With the exception of a 32 kW total energy facility in Albuquerque, New Mexico, no systems are now producing electricity. Several fairly expensive test facilities have been or are being built. The 10 MW central receiver experimental module in Barstow will have a capital cost of over $10,000 per peak kW.[20] Solar thermal power systems could be materials-intensive in quantity and quality. A central receiver system will require 15 times the construction materials (concrete and steel) needed by a nuclear plant and 35 times that of a coal plant.[20]

The DOE solar thermal power systems program cost goal for heliostats is $7/ft^2 of collector surface.[12] Present costs are $40/ft^2, or almost six times as high as the goal. The 1982

cost goal is $20/ft².[23] This means essentially that heliostat costs will have to be halved every 5 years. If the cost goals of this critical item can be met, electricity at 6 to 8 ¢/kWh in 1990 should be possible.

Distributed collector cost goals have also been established. In 1982, these goals are $22/ft² for dish collectors and $17/ft² for trough collectors.[23]

SOLAR PHOTOVOLTAIC SYSTEMS

A photovoltaic cell converts light directly into electrical energy. The modern cell was invented in 1954, and many of the cells built in the 1950s continue to operate today. A typical silicon cell is shown in Figure 10-18. An electromagnetic wave, such as light, is a shower of photons, with each photon having its energy and momentum. When this shower of photons interacts with the junction of a semiconductor device, an electric current is generated. Photovoltaic devices are used to power navigational warning lights, horns or unmanned offshore platforms, maritime buoys, remote educational television receivers, radio repeater stations, environmental monitoring equipment, railroad warning and signaling systems, and battery charges on small boats. They are also used for remote telephone power, water purification plants, desert water-pumping stations, and light measurement instruments.

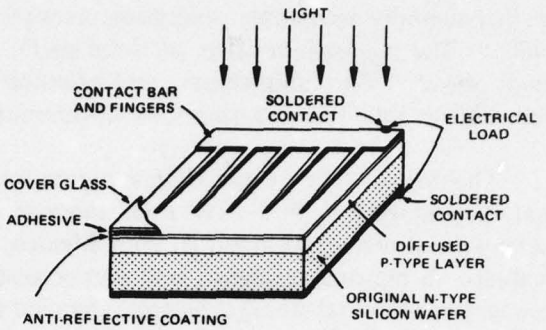


Figure 10-18. SILICON CELL

With the emergence of the energy crisis, it is desirable to use arrays of these devices to generate electrical power on a large scale. To accomplish this, DOE has established the following photovoltaic strategy:

- Support a strong, high-risk R&D effort.
- Support technology development toward cost goals.
- Support key process steps.
- Develop no federal manufacturing facilities.
- Exploit market pull stimulation.

Photovoltaic Cells

The term "solar cell" generally refers to silicon cells although alternative photovoltaic energy converters have been developed and tested. Silicon cells have the highest efficiencies yet obtained, but others such as cadmium sulfide and gallium arsenide cells, also have good photovoltaic properties.

Single Crystalline Silicon Cell

The single crystalline silicon solar cell is an efficient long-life photovoltaic device. This cell is used in the space program and nearly all the commercially available small terrestrial

systems. While the wafer silicon cell meets every requirement for large-scale terrestrial use, its use has been limited in the past because of high cost.

Since sand is the raw material for silicon, a sufficient quantity exists to support all foreseeable solar cell production. It would take approximately 16 metric tons of silicon to make a 1 MW power output (average power) solar array (15 percent conversion efficiency). The anticipated production of semiconductor-quality silicon alone in the United States in 1974 was estimated to be 1,240 metric tons. Metallurgical grade silicon currently sells for about $1/kg, but semiconductor grade sells for about $60 to $70/kg. DOE's goal is to reduce the cost of photovoltaic grade silicon, which is between these two, to about $10/kg.

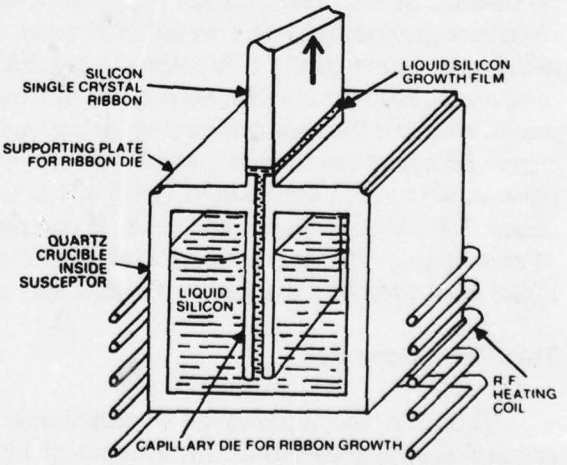
The present cost of space-rated solar cells is about $100 to $200 per peak watt of output. In 1978, DOE purchased flat-plate (nonconcentrator) photovoltaic arrays for less than $10 per peak watt.

The efficiencies of terrestrial silicon photovoltaic cells range from about 12 to 16 percent, with values above 20 percent attainable but at higher cost. (The efficiencies given are for the individual cells. The efficiencies of the arrays of cells are slightly lower.)

Silicon Ribbon Cell

The construction of the single-crystal silicon solar cell is comprised of a number of labor-intensive batch processes that make significant cost reductions difficult. This has led to a search for simpler ways to make silicon cells. About 1968, Tyco Laboratories, Inc. (the Mobil Tyco Solar Energy Corporation) began to develop a radically new crystal-growth process for the production of continuous-shaped single crystals of "sapphire" directly from the melt. The basic crystal-growth process, called "Edge-Defined, Film-Fed Growth (EFG)," has been adapted to the production of silicon ribbons, as shown in Figure 10-19.

In 1975, Mobil Tyco reported that they were able to grow 2.5 cm wide ribbons about 200 to 250 microns thick continuously to various lengths up to 21 m. Mobil Tyco has continued to refine the process and can now make 7.6 cm ribbons.[24] The demonstrated and developmental goals for the program are displayed in Table 10-3.



Source: Martin Wolf, "Photovoltaic Power," *Astronautics and Aeronautics,* XIII, 11 November 1975.

Figure 10-19. PRODUCING EDGE-DEFINED FILM SILICON

Cadmium Sulfide Cell

The cadmium sulfide (CdS) cell offers the promise of low costs but has in the past offered low efficiency (2 to 3 percent) and short life (2 years). Now, however, peak perfor-

Table 10-3. GOALS FOR THE MOBIL TYCO SILICON RIBBON CELL PROGRAM

Parameter	Demonstrated Conditions as of Early 1978	End 1978 Goals	1986 Goals
Ribbon width	3 in.; single station furnace	3 in.	3 in.
Growth rate	1.5 in./min flat ribbon, >2 in./ min buckled ribbon	3 in./min	3 in./min
Thickness	.008 to .015 in.	0.010 in.	0.006 in.
Ribbons per operator	5 from 2 in. cartridges; low duty rate	5×2 in.	10×3 in.
Run length	20 hours; two multiple growth demonstration runs	24 hours	116 hours
Machine duty rate	0.3 to 0.4	0.70	0.83
Yield	Not previously defined	0.70	0.90
Cell efficiency	10 percent occasionally; 5 percent to 8 percent routinely	≥9%	12%

Source: B. H. Mackintosh and others, "Multiple Silicon Ribbon Growth by EFG," presented at the Thirteenth IEEE Photovoltaic Specialists Conference, Washington, D.C., 5-8 June 1978, IEEE Catalog No. 78CH1319-3.

mances between 7.0 and 9.2 percent have been demonstrated, and cell life has started to increase.[5,23] Efficiencies above 10 percent are possible in the near term, and lifetimes in excess of 20 years are achievable through improved encapsulation.[26]

Thin-film CdS cells are made in several steps: a thin layer of zinc is evaporated onto a plastic substrate; spectroscopically pure CdS is evaporated over this zinc layer; the CdS is dipped into a bath containing copper ions, which forms the copper sulfide essential to the operation of the cell; the edges of the cell are trimmed off; a copper grid is placed in contact with the treated surface (the copper may be cemented to the copper sulfide with conducting epoxy); a layer of transparent plastic is placed over the structure and the edges are sealed by heat. Contacts to both the CdS and the copper grid are left exposed during the last step.[27]

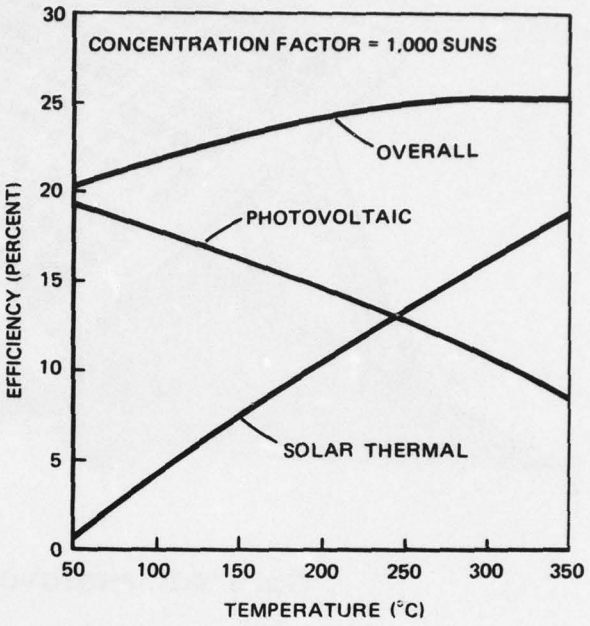
The raw materials, sulfur and cadmium, are in sufficient supply to tolerate a significant production of CdS cells. Sulfur is plentiful, and the amount needed for a CdS solar-cell electricity-generating system would only make a small demand on the supply. Present cadmium production in the United States is 3,000 metric tons per year, and U.S. and world reserves are 205,000 and 850,000 metric tons respectively (reserves indicate the cadmium that can be obtained through zinc mining; actual cadmium resources are considerably greater but cannot be mined economically at present). Eight percent efficient CdS solar cells 20 microns thick would require approximately 4.5 metric tons of cadmium/MW of average power produced.[28] The availability of cadmium is complicated because it is obtained as a by-product of zinc mining. The economic problems involved in increasing production to meet the cadmium need without a market for the zinc may constitute a major problem.

Thin-Film Silicon Cell

Thin-film silicon photovoltaic cells should reduce the cost of manufacturing the silicon cell and significantly reduce the amount of high-grade silicon necessary for a cell. Unfortunately, the efficiency of these cells a few years ago was well below 2 percent. Recently, efficiencies of about 9 percent have been achieved for the best cells in a laboratory development.[29] If thin-film cells can be mass-produced with efficiencies exceeding 10 percent they will be contenders for the major solar cell applications. The fabrication steps for thin-film silicon cells are preparation of trichlorosilane, deposition of solar-cell structure on low-cost substrates by the reduction of trichlorosilane, contact and lead attachment, and encapsulation.[30]

Gallium Arsenide Cell

Gallium arsenide (GaAs) cells, among the most promising of the photovoltaic cells for concentrator applications, have demonstrated efficiencies above 15 percent. Although the individual cells are not low-cost, systems using them might be low in cost because they can be used with concentrators. Varian Associates reported that experimental cells have operated at a concentration ratio of 1,735:1 with an output power density of 0.24 MW/m² of cell area.[31] In such a situation, the cost of the concentrator, not the photovoltaic cell, becomes the important economic factor. The concentrator/GaAs cell also has good potential in combined photovoltaic-solar thermal systems where efficiencies over 25 percent are possible, as shown in Figure 10-20. In areas such as the southwestern United States, where large amounts of direct sunlight are available, the concentrator/GaAs system seems promising for large-scale use.



Source: *Electronics*, 11 November 1976.

Figure 10-20. EFFICIENCY OF A COMBINED GaAs PHOTOVOLTAIC-SOLAR THERMAL CONVERSION SYSTEM

Photovoltaic Collection and Concentrating Devices

Many photovoltaic cells are needed to collect and convert solar energy to electrical energy at levels needed for most applications. The most common practice is to assemble banks or arrays of these cells as shown in Figure 10-21. These arrays may have either simple fixed exposure to the sun or they may be combined with the concentrator and tracking systems used for solar thermal power generation to enhance energy collection.

Conversion and Storage

The electricity generated by photovoltaic cell arrays is direct current (DC). Although there are various small-scale, remote area applications that could use direct current electricity, most demands are for alternative current supply. Therefore, part of any photovoltaic system is a converter to make the systems compatible with conventional electric power supply.

A second component needed for self-sufficient photovoltaic systems is energy storage. The stored energy could be used during periods when sunlight is unavailable. Various storage methods have been developed, such as pumping water into elevated basins and retrieving the energy by turbogenerators (similar to hydroelectric power generation), and manufactur-

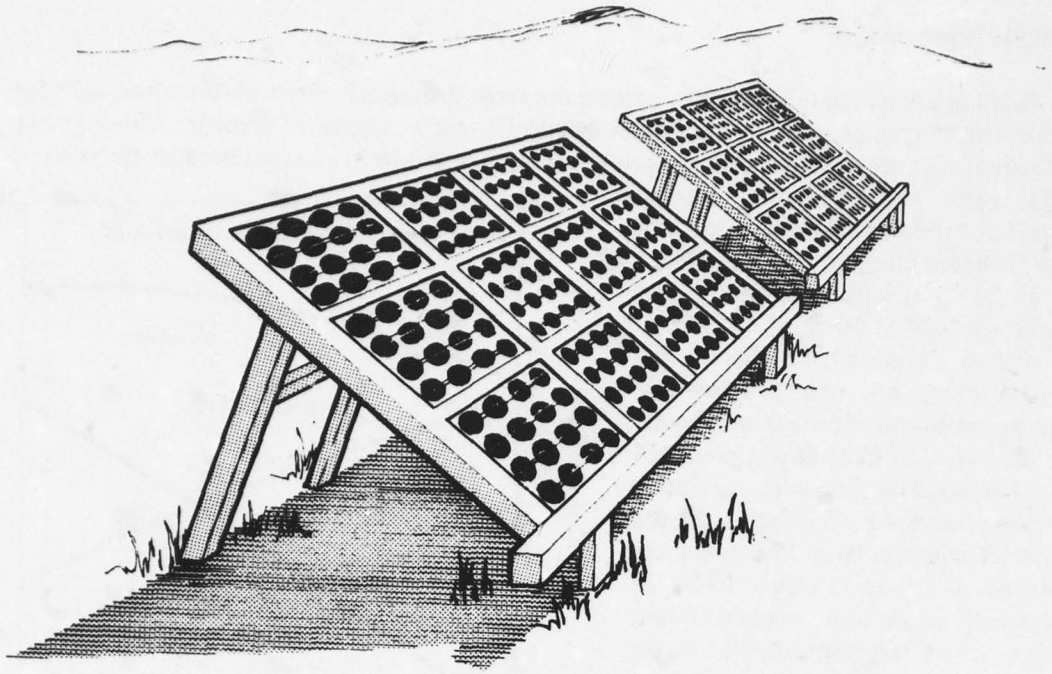


Figure 10-21. PHOTOVOLTAIC ARRAYS

ing hydrogen through the electrolysis of water. The hydrogen could be burned subsequently or fed into fuel cells.[32]

Space Satellite Photovoltaic Power Systems

Because the amount of sunlight available on the earth's surface is limited by the earth's rotation, cloud cover, atmospheric attenuation, and other factors, the feasibility of space satellite photovoltaic power systems is being investigated. The sunlight availability factors for a satellite in synchronous orbit are shown in Table 10-4. A proposed space satellite power system is shown in Figure 10-22; an overall efficiency estimate for this system is shown in Figure 10-23. Figure 10-24 shows a variant satellite power system using concentrators. When the efficiency of 68 percent is combined with the sunlight availability gain of 15, the space satellite offers about a 10 to 1 gain in the use of solar cells. Orbiting such a large satellite, however, would not only be expensive but also raise environmental questions about the microwave beam.

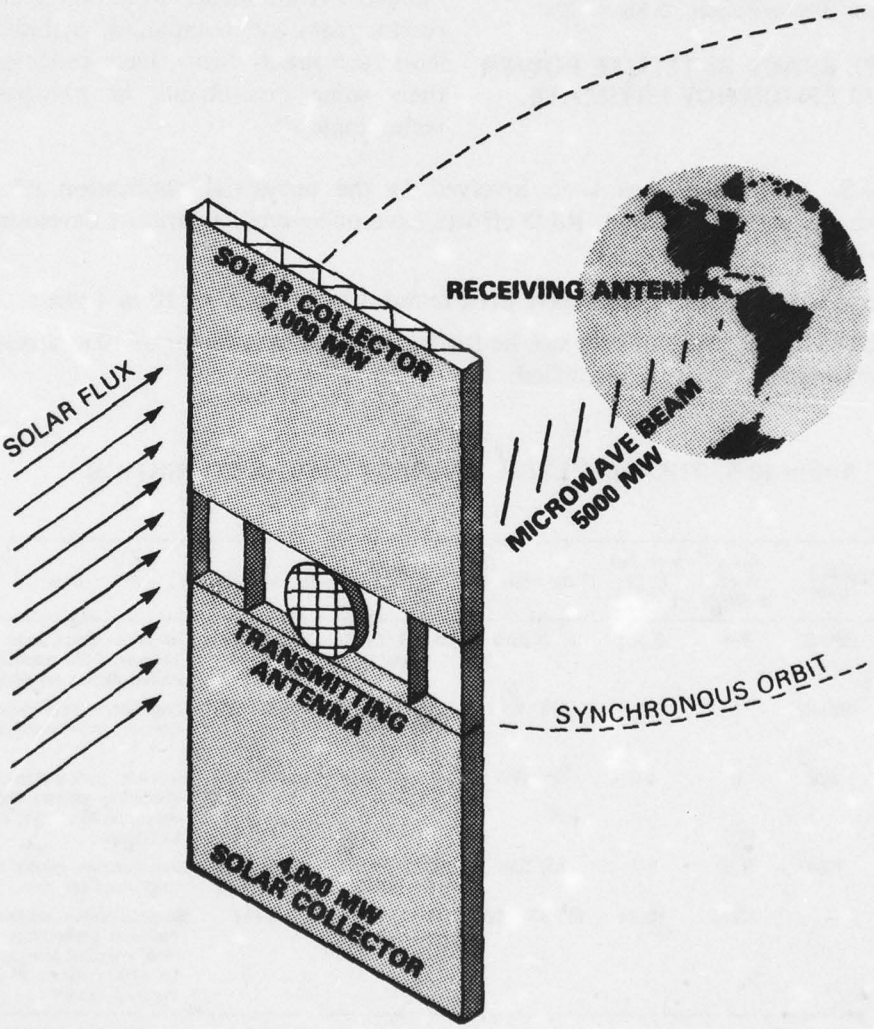
Applications

The federal government has tabulated the characteristics of five photovoltaic markets based on economic and other studies (see Table 10-5). Whether these market characteristics

Table 10-4. AVERAGE AVAILABILITY OF SOLAR ENERGY

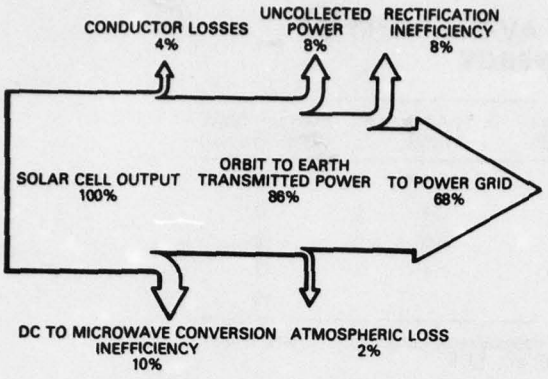
Availability Factor	Average on Earth	In Synchronous Orbit	Average Ratio (Orbit/Ground)
Solar energy density (kW/m²)	1.1	1.4	5/4
Hours of useful radiation/day	8	24	3
Percentage of clear skies	50	100	2
Average angle of incidence factor	0.5	1	2
Product of all factors			15

Source: J. T. Patha and G. R. Woodcock, "Feasibility of Large-Scale Orbital Solar/Thermal Power Generation," *Proceedings IECEC*, 1973.



Source: Peter E. Glaser, "Space Satellite Power System," Solar Energy Lecture III, IEEE Washington, 28 March 1974.

Figure 10-22. SPACE SATELLITE POWER SYSTEM



Source: Peter E. Glaser, "Space Satellite Power System," Solar Energy Lecture III, IEEE Washington, 28 March 1974.

Figure 10-23. SPACE SATELLITE POWER SYSTEM EFFICIENCY ESTIMATE

can be achieved depends largely on the development of low-cost photovoltaic cells and on the overall system capital and operative costs achievable.

Research and Development Programs

Various federal government, industrial, and private organizations are conducting significant R&D projects in photovoltaic power generation. DOE has allotted $76 million to photovoltaics in the FY 1979 budget. Private efforts have accelerated in recent years; oil companies, including at least four major firms, have concentrated their solar investments in photovoltaic technologies.[20]

The U.S. government has been involved in the terrestrial application of solar photovoltaics since 1975. To date, R&D efforts have uncovered significant developments and initiatives:

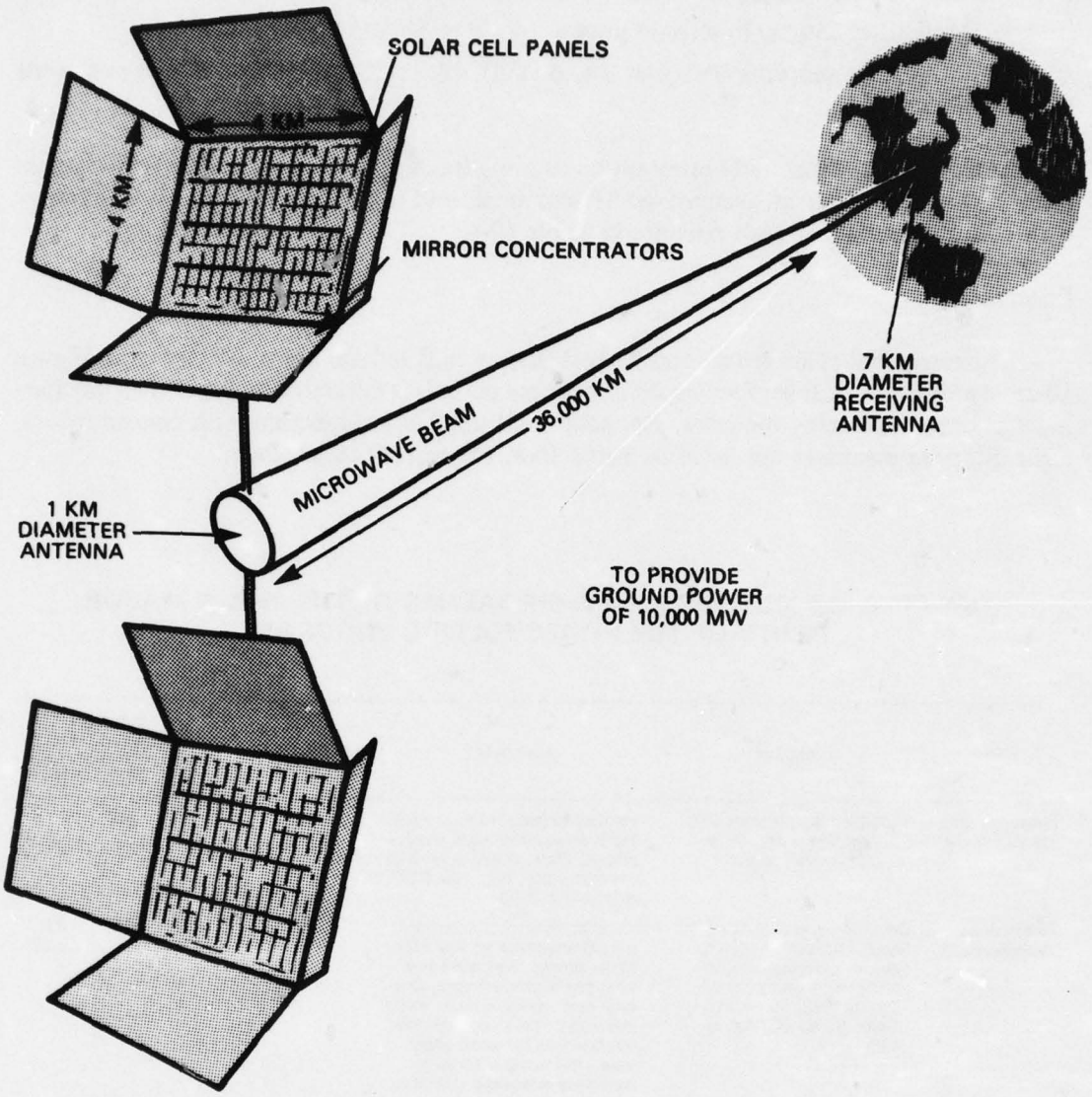
- Silicon solar cell array costs have been reduced by a factor of 10 in 4 years.
- Manufacturing costs for cells can be further reduced by a factor of 10 as a result of improvements currently identified.

Table 10-5. PHOTOVOLTAIC MARKET CHARACTERISTICS

Photovoltaic Market	Start Date	Array Price ($/Wp[a])	Installed Price ($/Wp)	Total Market	Annual Market	System Size	Use
Federal	1980-82	4-6	8-15	>100 GW	10-100 MW/ year	10-200 kW	Office buildings, load centers, DOD applications, native American villages
Residential	1985-86	1	2	175 GW	3-10 GW/ year (1986 and later)	2-500 kW	Single and multifamily residences, small villages
Industrial/ commercial	1982	2	4-6	100 GW	1-2 GW/year (1990)	10-500 kW	Schools, light industry, shopping centers, highways, retail stores, office buildings
Utility	1986	0.50	1-2	100 GW	10-20 GW/ year (1990)	10-100 MW	Communities, central utilities large load centers
Rural/remote	—	12-15	15-25	150-300 MW	20-30 MW/ year (1985)	1-5 kW	Remote communications, cathodic protection, irrigation, medical refrigeration, weather stations in developing nations

[a]Wp = Peak watt.

Source: Paul D. Maycock, "The Development of Photovoltaics as a Power Source of Large-Scale Terrestrial Application," presented at the Thirteenth IEEE Photovoltaic Specialists Conference, Washington, D.C., 5-8 June 1978, IEEE Catalog No. 78CH1319-3.



Source: Martin Wolf, Hearings before the Subcommittee on Energy of the Committee on Science and Astronautics, U.S. House of Representatives, 6 and 11 June 1974.

Figure 10-24. SPACE SATELLITE POWER SYSTEM WITH CONCENTRATORS

- Silicon material costs can be reduced by a factor of 5.
- Concentrator solar cell arrays can meet a $2 per peak watt cost goal in 1979.
- Industry is spending risk capital on photovoltaic programs.
- The market will begin a rapid growth phase at $1 to $2 per peak watt.
- Two private ventures are under way on CdS solar cells with a $1 to $2 per peak watt cost goal.

The current federal R&D program on photovoltaics is divided into three major parts: research and development, technology development, and tests and applications. The objectives and approaches of each part are in Table 10-6.

Economics

The terrestrial solar array module cost history and federal goals are shown in Figure 10-25. The cost breakdown for two different time periods is tabulated in Table 10-7, for flat-plate photovoltaic array modules. For solar cells used in conjunction with concentrators, eight different estimates are listed in Table 10-8, for current technology.

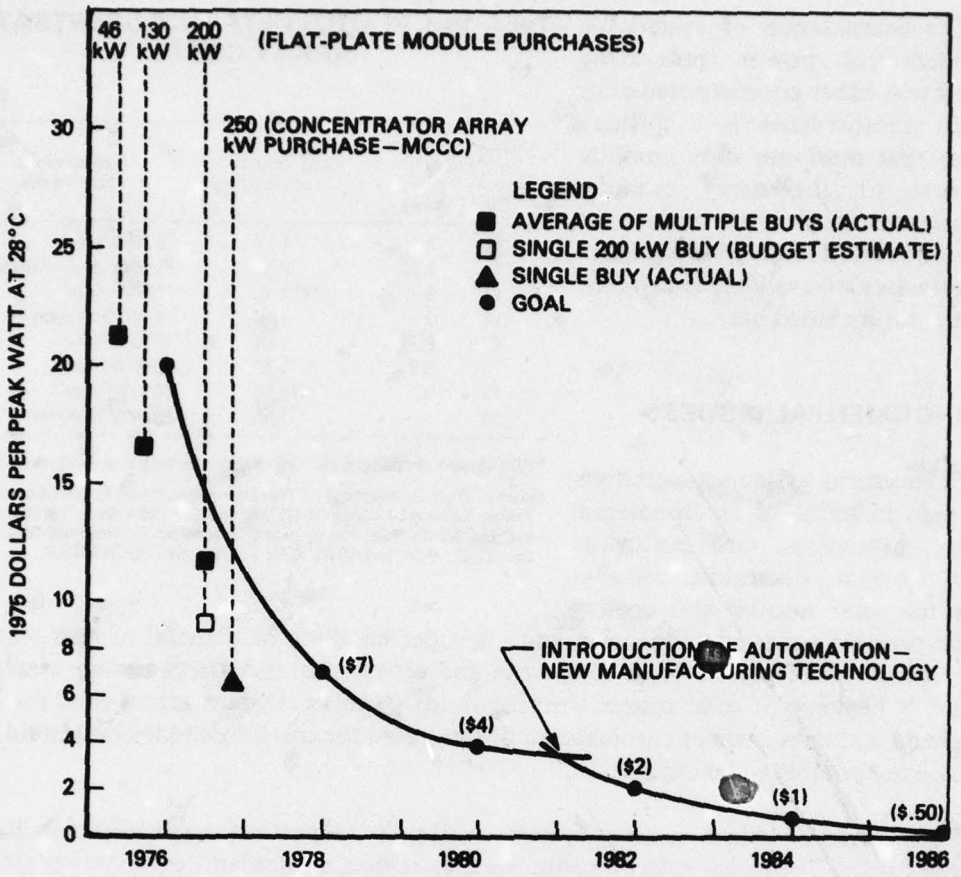
Table 10-6. OBJECTIVES AND APPROACHES OF THE THREE MAJOR PARTS OF THE PHOTOVOLTAIC PROGRAM

Part	Objective	Approach	Manager	Funding (Millions of dollars)		
				1977	1978	1979
Research and development	Increase performance (efficiency, life, intrinsic low cost, breakthrough)	Unsolicited proposals; program R&D announcements (amorphous, films, other materials, mechanisms); high risk R&D grants (FY 1979)	SERI	6.2	8.7	13.5 (+22.0)
Technology development	Develop several options for each production step to assure meeting program array price goals of: $2/Wp in 1982; $0.50/Wp in 1986; $0.10-.30/Wp in 1990	Divide array and concentrator manufacturing into key functional steps; determine present costs of each step; allocate cost goals to each step; support three to five specific approaches for each step; weed out nonperformers; purchase adequate arrays to evaluate new approaches and track price	JPL	30	36[a]	33 (+10)
Tests and applications	Systems design, test, standards, and support of early market pull for energy saving applications	Mission analysis; planning; centers of excellence (systems/tests); federal experiments irrigation; cyclical program R&D announcements (concentrator/flat-plate)	Sandia, ALO	7	31[a]	50[b]

[a]Includes supplemental.

[b]Includes NEA.

Source: Paul D. Maycock, "The Development of Photovoltaics as a Power Source of Large-Scale Terrestrial Application," presented at the Thirteenth IEEE Photovoltaic Specialists Conference, Washington, D.C., 5-8 June 1978, IEEE Catalog No. 78CH1319-3.



Source: Paul D. Maycock, The Development of Photovoltaics as a Power Source of Large-Scale Terrestrial Application," presented at the Thirteenth IEEE Photovoltaic Specialists Conference, Washington, D.C., 5-8 June, IEEE Catalog No. 78CH1319-3.

Figure 10-25. TERRESTRIAL SOLAR ARRAY MODULE COST HISTORY AND GOALS

Table 10-7. SILICON FLAT PLATE ARRAY COST BREAKDOWN

Process	Price $/Peak Watt (1975 dollars)		Technology Program Status
	1976 Actual	1982 Goal	
Make poly silicon	2.01 ($65/kg)	.28 ($20/kg)	4 to 6 approaches $20 million to $40 million plants 2 years to build
Make crystal area (from poly silicon)	4.18	.67	Ribbon No breakthrough
Fabricate cells	5.97	.58	TI, Motorola, RCA all forecast < .58
Encapsulate and assemble	4.77	.47	Not clear yet
Total	16.93	2.00	

Source: Paul D. Maycock, "The Development of Photovoltaics as a Power Source of Large-Scale Terrestrial Application," presented at the Thirteenth IEEE Photovoltaic Specialists Conference, Washington, D.C., 5-8 June 1978, IEEE Catalog No. 78CH1319-3.

The computation of costs/kWh for electrical power generating systems that either are composed of or contain photovoltaics is a difficult process that must not only consider the cost of the array modules themselves but also an extensive list of other items and factors. Only conceptual estimates are available at this time and are not included here.

Table 10-8. PHOTOVOLTAIC CONCENTRATOR ARRAY COSTS

Assumed Efficiency (Percent)		Cost Projection ($/Wp)[a]	Assumptions, Comments
Cell	Array		
12	7	1.72	10 MW/year
12	9.7	2.21	Present-day equipment
12	9	1.59	10 MW/year
12	9	1.85	10-100 MW/year in 1978
12	9	1.94	10 MW/year
—	9.9	1.81	10 MW/year
12	9	2.31	10 MW/year
10	—	1.19	Several MW/day

[a]1976 dollars, FOB factory. Conclusion: industry says $2/watt now.

Source: Paul D. Maycock, "The Development of Photovoltaics as a Power Source of Large-Scale Terrestrial Application," presented at the Thirteenth IEEE Photovoltaic Specialists Conference, Washington, D.C., 5-8 June 1978, IEEE Catalog No. 78CH1319-3.

ENVIRONMENTAL ISSUES

Solar energy systems are relatively benign in terms of environmental effects, producing few pollutants under normal operation. Similar issues for solar heating and cooling include possible water contamination and improper handling or disposal of heat transfer fluids, which could pollute local waterways and ecosystems and affect sewage treatment plants.[12,13] Leakage of solar system working fluids (such as ethylene glycol used for antifreeze) and additives (such as chromates or nitrates used for corrosion inhibition) could contaminate the potable water supply.

Solar thermal central receiver systems will emit no particulates, sulfur dioxide, or nitrogen oxides. The major environmental issue associated with solar thermal power systems is stray reflections from heliostats.[5] Other key environmental issues are improper handling and disposal of system fluids and wastes, ecological effects of the heliostat field, potable water contamination, alteration of the microclimate, and land use.

Improper handling and disposal of system fluids and wastes from solar thermal power plants could cause fires and explosions, contaminate drinking water supplies, increase soil salinity, and affect local flora and fauna. Sewage treatment plants may also be affected. In total energy systems, working fluid additives may leak into the domestic hot water system, resulting in contamination of the potable water supply. Of primary concern are the highly toxic properties of certain additives, particularly the chromates and nitrates. During all phases of heliostat fabrication and use, severe burns, eye injury, fires, and hazardous traffic conditions may occur. Construction and operation of the heliostat field could affect local flora and fauna and hydrology patterns. Alteration of the microclimate, resulting from solar central power system operations, may adversely affect indigenous wildlife and vegetation. Land utilization by solar dispersed power facilities can restrict alternative land uses and significantly modify community land use plans.[10]

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11. WIND ENERGY

Wind energy is a clean, renewable energy source and, though it is intermittent and its energy density is low compared with that of fossil and nuclear fuels, it constitutes a large, practically untapped energy resource. Wind systems could displace an estimated 2 to 3 quads of fossil fuels by 2000.[1]

Wind energy has been used for a long time to power ships and agricultural devices, such as those used to pump water for irrigation or grinding grain. Horizontal-axis windmills with sails wrapped on wooden booms, still seen in many Mediterranean regions, have been in use for centuries. The old "Dutch" windmill, consisting of four arms with wooden bars supporting sail cloth, existed at least 500 years ago. In the United States, more than 6 million windmills (each less than 1 kW) were used to pump water and generate electricity before 1950, and approximately 150,000 are still operating.[2]

From 1935 to 1955, a number of large experimental wind powered generators were constructed. Most of these units were located in Europe; the Smith-Putnam unit at Grandpa's Knob, Vermont, was the only U.S. effort. In October 1941, the Smith-Putnam unit was the first ever to feed wind generated power synchronously into a utility power grid. Rated at 1,250 kW in a 30 MPH wind, it was operated experimentally for 1,100 hours over 4½ years until a blade failure in March 1945; the project was discontinued for economic reasons. Recent studies have indicated that such systems costing $500 to $750/kW installed are economically practical if fuel costs are high. Consequently, many utility companies have expressed interest in wind energy conversion systems.

The majority of windmills developed in the future are expected to be used to generate electric power. Currently, large wind systems (1 to 3 MW) for integration with utility grids, as well as small (5 to 10 kW) and intermediate-sized (100 to 200 kW) wind machines are being developed. In addition, the mechanical energy from wind turbines can be used for direct heat applications such as space heating.

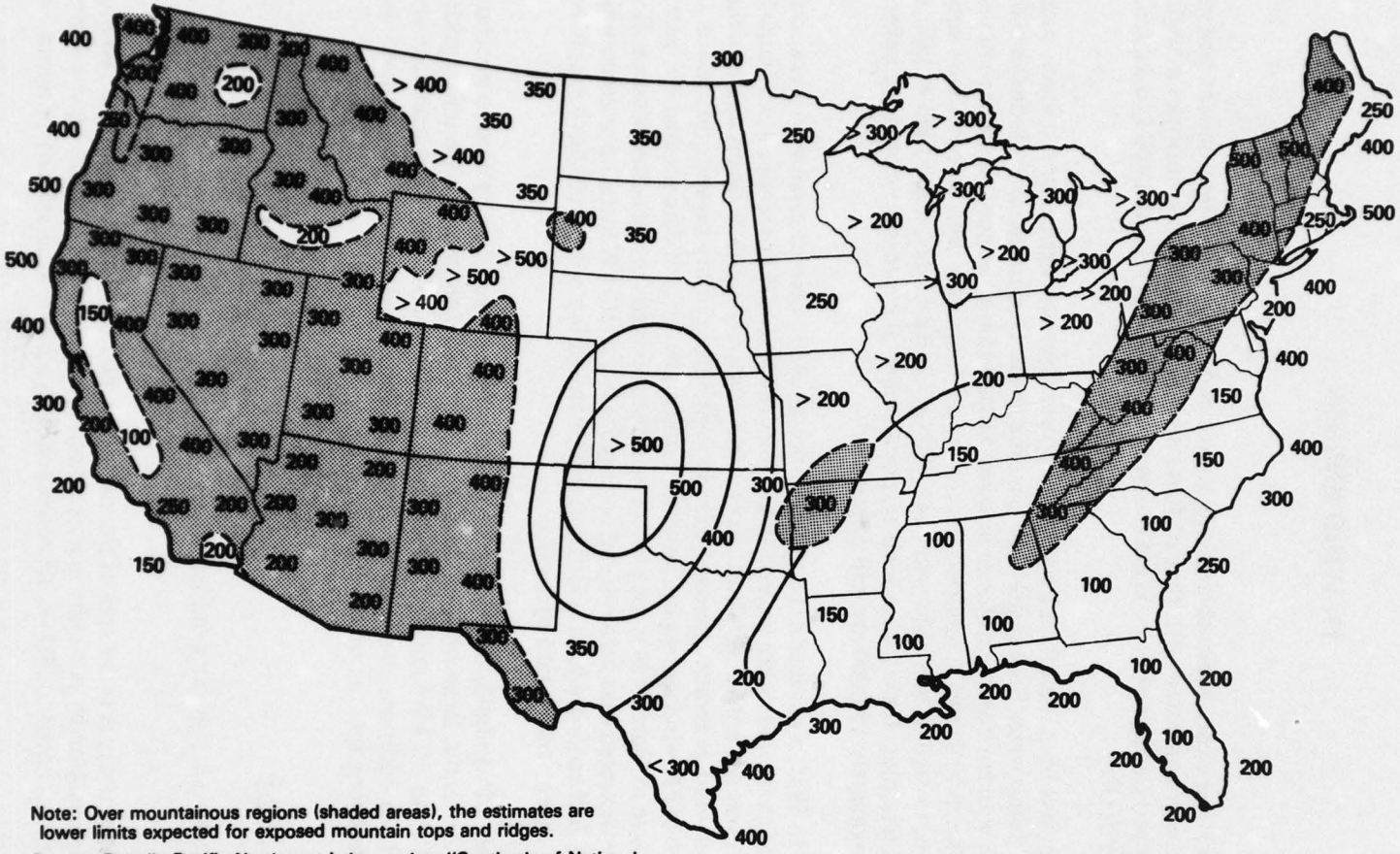
WIND RESOURCES

The available power in the wind is:

$$P = \tfrac{1}{2} \rho A v^3$$

where ρ is the air density, A is the area of the rotor disc, and v is the wind velocity. Dividing both sides of the equation by A results in power/unit area, expressed in watts/square meter (W/m^2). Wind power equal to 500 W/m^2 corresponds to a mean wind velocity of about 9.4 m/s (21 MPH).

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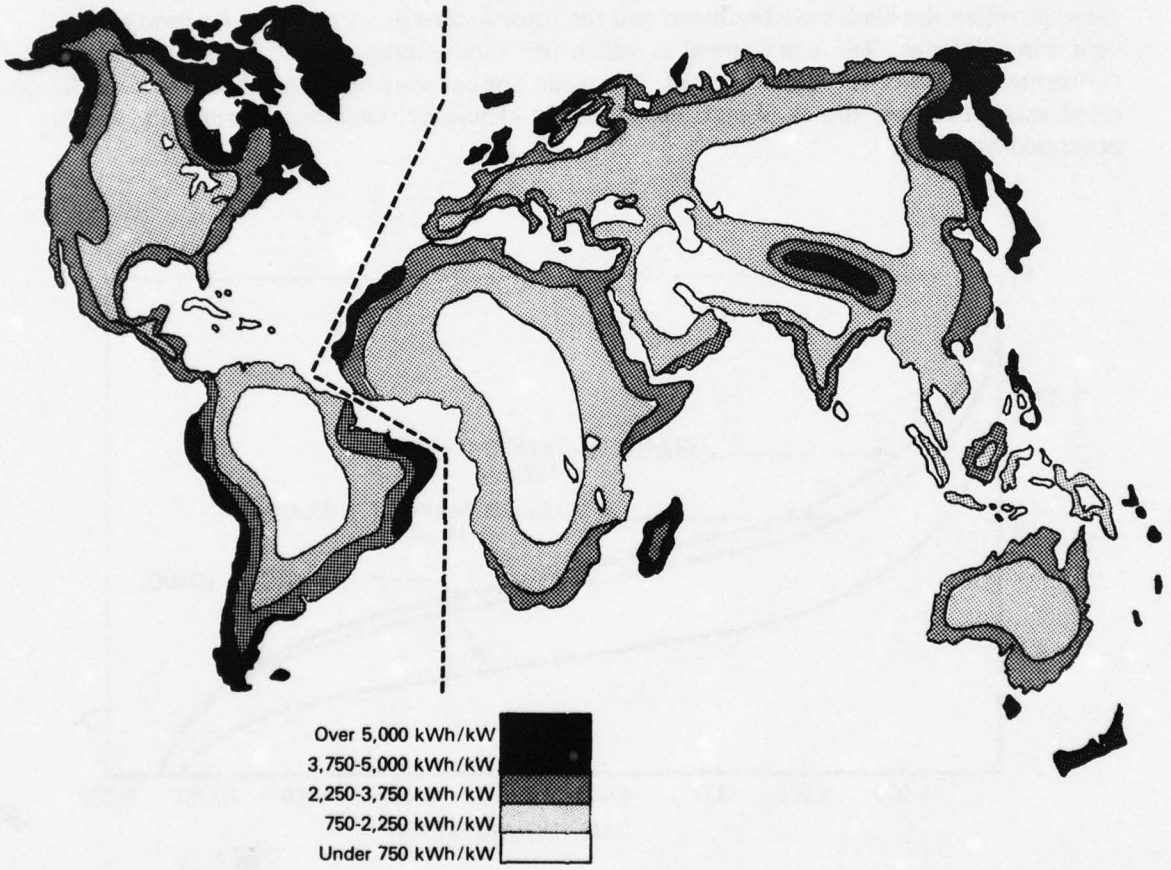


Note: Over mountainous regions (shaded areas), the estimates are lower limits expected for exposed mountain tops and ridges.

Source: Battelle Pacific Northwest Laboratories, "Synthesis of National Wind Energy Assessments," BNW/WIND-5, July 1977.

Figure 11-1. MEAN ANNUAL WIND POWER (W/m^2) ESTIMATED AT 50 m ABOVE EXPOSED AREAS

Figure 11-1 shows the distribution of the annual mean of this power in the United States at a representative hub height (50 m) for large wind turbines.[3] Generally, mountainous areas located between 25 and 60 degrees latitude are windy. U.S. areas with the most desirable wind characteristics include various islands, Alaska, the Great Plains, the high desert, and the Rockies, with additional potential in the Great Lakes, New England, and coastal zones.[4] As indicated in Figure 11-2, windy continental regions outside the United States include Labrador and the Maritime Provinces of Canada, the Andes and Venezuela in South America, the Alps of Central Europe, the Apennines of Italy, the Guadarrames of Spain, the Pyrenees of Spain and France, the Carpathians of Poland, the Urals of Russia, the Himalayas of India and Tibet, the Deccan of India, the Kamchatka Peninsula of Russia, and Antarctica.[5]



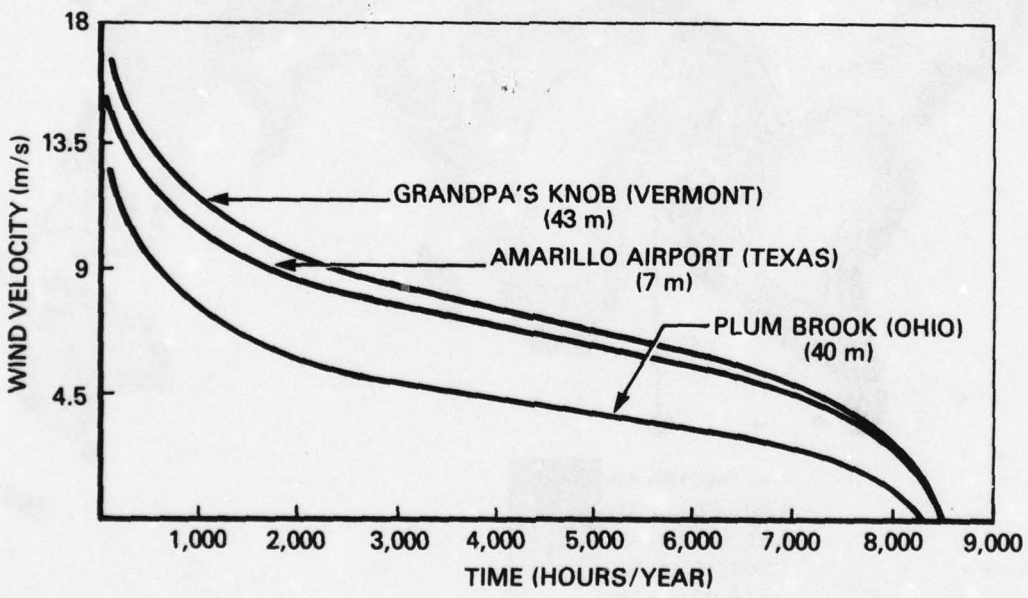
Note: Availability is in terms of estimated number of kWh/year per rated kilowatt output for wind machines designed for rated wind speeds of 25 MPH.

Source: The Mitre Corporation, "Wind Machines," NSF-RA-N-75-051, October 1975.

Figure 11-2. ANNUAL AVAILABILITY OF WIND ENERGY IN DIFFERENT PARTS OF THE WORLD

Ideally, a wind turbine should extract about 59 percent of the energy in the wind, but it actually extracts no more than about 80 percent of the 59 percent, for a power coefficient of 0.47. The power output of a wind turbine can be estimated crudely by multiplying wind power by 0.47 and by the swept area of the wind turbine. (This estimate is especially crude for mountainous areas.)

The power output for a wind turbine at a particular site can be calculated more accurately using velocity duration values and the characteristics for a given windmill system. Velocity duration values are often given in a curve, which shows the number of hours per year that a certain wind velocity is exceeded at a particular site.[6] Figure 11-3 shows annual average velocity duration curves for three sites. Power versus wind velocity is shown in Figure 11-4 for a typical wind energy conversion system. The cut-in speed is the minimum wind speed at which the system delivers power to the utility grid network; the cut-out speed, the maximum wind speed at which the system is allowed to function, represents the wind speed at which the blades are feathered and the rotor locked in a stationary position to prevent wind damage. The wind speed at which the wind energy conversion system begins delivering full power is the rated speed. The mean annual wind speed must be less than the rated speed to allow the maximum aerodynamic efficiency, thus maximizing the energy generated annually.



Source: The Mitre Corporation, "Wind Machines," NSF-RA-N-75-051, October 1975.

Figure 11-3. ANNUAL AVERAGE VELOCITY DURATION CURVES FOR THREE SITES

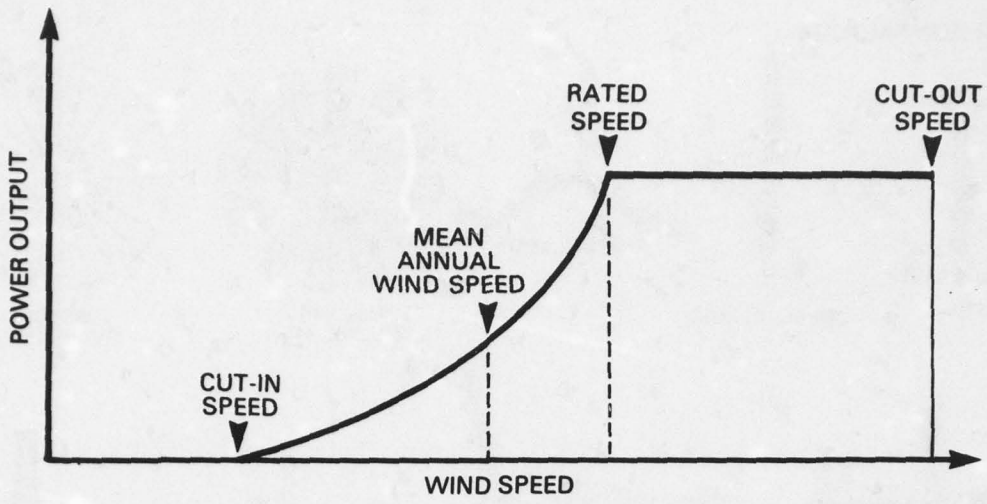


Figure 11-4. POWER VERSUS WIND VELOCITY OF TYPICAL WIND ENERGY CONVERSION SYSTEM

WIND TURBINE DESIGN

A variety of devices can be used to extract energy from the wind. Figure 11-5 shows various possibilities. Rotating wind turbines, the most common devices, have axes of rotation that are either parallel (horizontal) or perpendicular (vertical) to the flow of the wind; the rotor can be upwind or downwind of the supporting tower. Although any number of blades can be used, the most common wind turbine is a two- or three-bladed, horizontal-axis machine. Three-bladed machines generally have a better dynamic response than two-bladed machines, but most large machines (100 kW or greater) are two-bladed because of the dominance of blade costs at this size.

Horizontal-axis designs require some means of keeping the turbine oriented into the wind. Small windmills may be provided with a tail vane to turn them into the wind, or, if their blades are mounted downwind of the tower, the wind pressure on them may make them self-orienting. For large machines, an electrically driven yawing motor controlled by a small yaw-vane is used for orientation.

Vertical-axis turbines do not require orientation to the wind because they are omnidirectional, with the axis of rotation perpendicular to the wind regardless of the wind's direction. This omnidirectional characteristic and a capability of delivering power directly to ground level are the primary assets of these turbines. The results of recent tests made with two and three blades indicate that there are fewer structural problems with vertical axis turbines than with horizontal axis turbines.

The high-speed (two- or three-bladed, upwind or downwind) horizontal-axis wind machine is as efficient as any system available, extracting about 80 percent as much power as

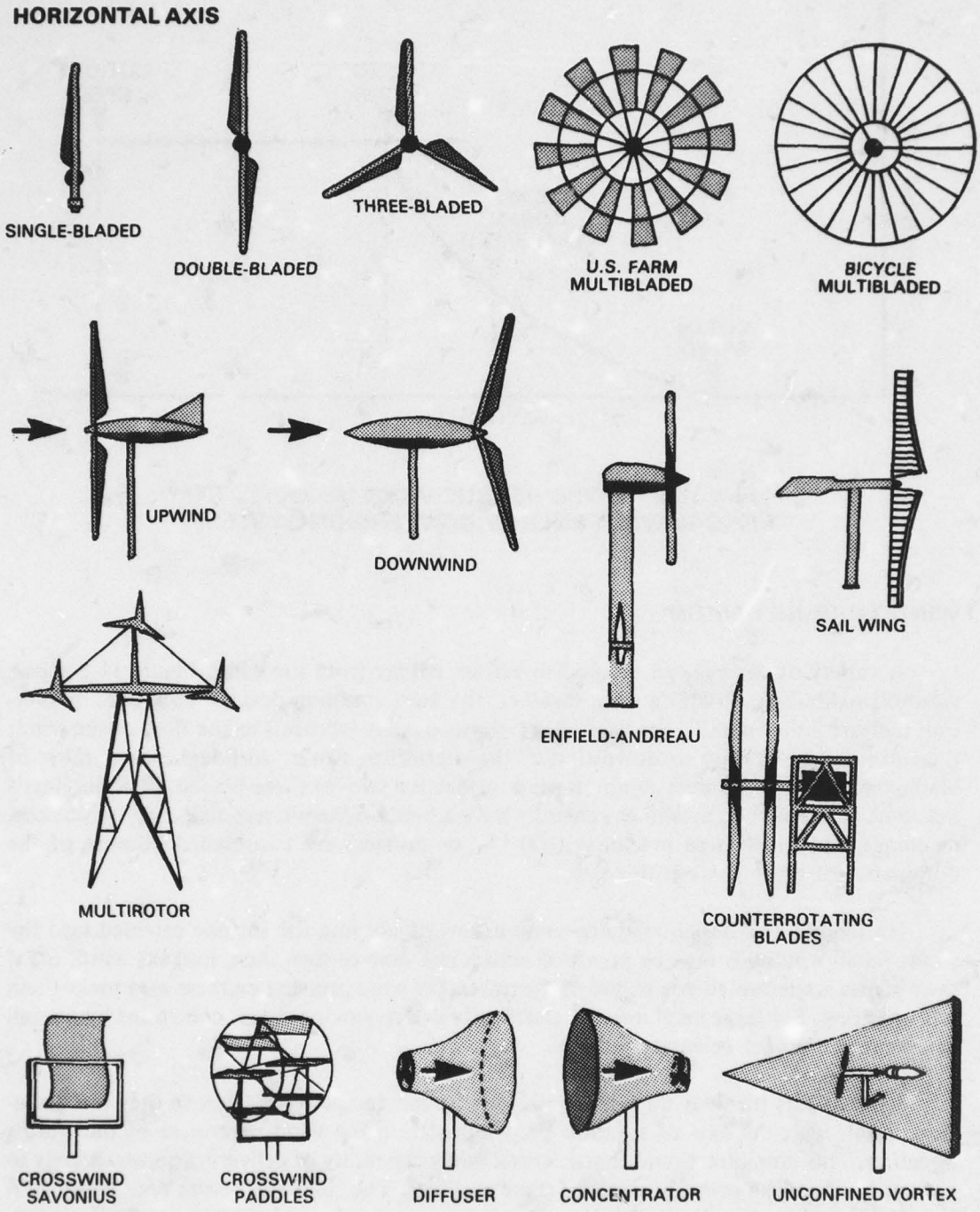
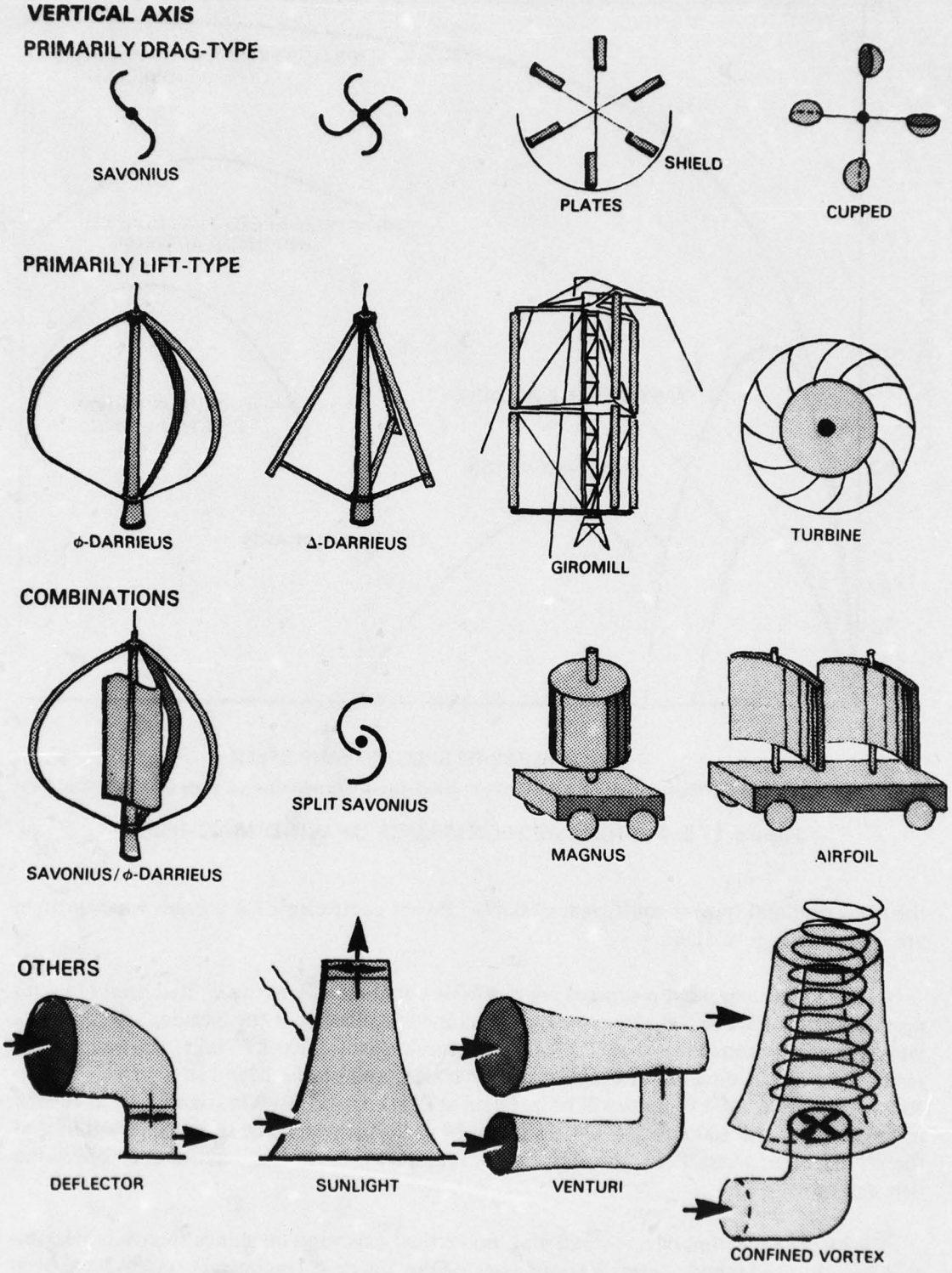
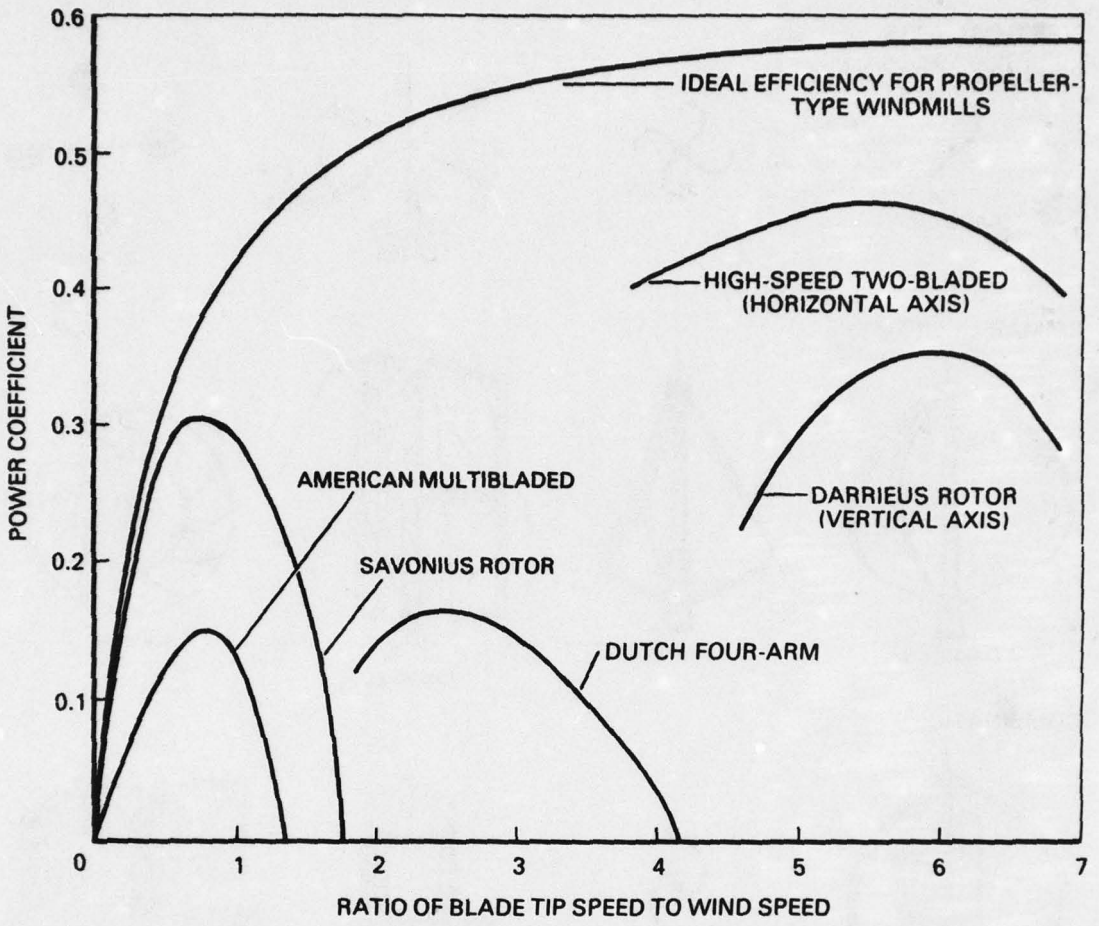


Figure 11-5. CLASSIFICATION OF WIND MACHINES



Source: The Mitre Corporation, "Wind Machines," NSF-RA-N-75-051, October 1975.

Figure 11-5. CLASSIFICATION OF WIND MACHINES (CONT'D)



Source: Robert E. Wilson, *Applied Aerodynamics of Wind Power Machines* (Oregon State University, May 1974).

Figure 11-6. TYPICAL PERFORMANCE OF WIND MACHINES

the ideal windmill (power coefficient of 0.47).[7] Power coefficients for various wind turbines are shown in Figure 11-6.

Horizontal-axis wind machines are available commercially in the United States in sizes up to about 20 kW. A 100 kW prototype machine is operating at the National Aeronautics and Space Administration (NASA) Lewis Research Center; 200 kW units are being field-tested by utility companies at Clayton, New Mexico, and on the Island of Culebra, Puerto Rico. Additional 200 kW units will be installed at Block Island, Rhode Island, and in Hawaii in 1979. All of the 100 and 200 kW units are 38 m in diameter. The technical feasibility of these machines has been proved, and remote, unattended, automatic operation demonstrated.

With the exception of one small unit, no vertical-axis wind machines are available commercially in the United States. Various sizes of the Darrieus (eggbeater) system have been tested, however. The Darrieus rotor has been tested up to 60 kW, performing without major

problems. Although the Darrieus rotor is not self-starting, it was combined with the Savonius rotor and tested at Sandia Laboratories in Albuquerque, New Mexico, to develop a self-starting hybrid unit. Combinations of Darrieus and Savonius are appropriate for low-power systems used in isolated regions. Larger systems probably will use an electric motor for starting. The largest Darrieus rotor in the United States is the 17 m unit at Sandia Laboratories. (The Canadians tested a 200 kW unit that was 24 m in diameter and 37 m high. This unit was destroyed accidentally in mid-1978.[8])

TURBINE FORCES

Regardless of the configuration, all rotors share the same design problem; they must endure certain stresses and forces induced during operation. Resonance and vibration may be minimized by careful design engineering of the rotor, driven machinery, and supporting structure, but aerodynamic and inertial forces must be countered by strength and rigidity, protected against, or both. Aerodynamic loads are generated both by uniform and nonuniform wind speed. The mean axial wind component generates thrust forces that deflect the blades downwind (forced coning), and variations in wind speed induce variations in the coning angle (flapping). Gradients in axial velocity (primarily vertical due to the boundary layer effect) tend to tilt the rotor disk with respect to the shaft, contributing to flapping and aggravating resonance problems at certain rotor speeds. Uneven loading of the blades also induces twisting stresses in the blades. Velocity components perpendicular to the rotor axis produce disk tilting and higher harmonic loadings.

Inertial blade loadings include centrifugal tension due to rotation, lead-lag, and flapping loads due to Coriolis forces arising from blade oscillations. Changes in wind direction produce gyroscopic precessional forces in horizontal-axis turbines as the unit pivots to maintain alignment with the wind vector. Although vertical-axis rotors do not need to track the wind, changes in the angle and direction of tower deflection produce small precessional loadings.

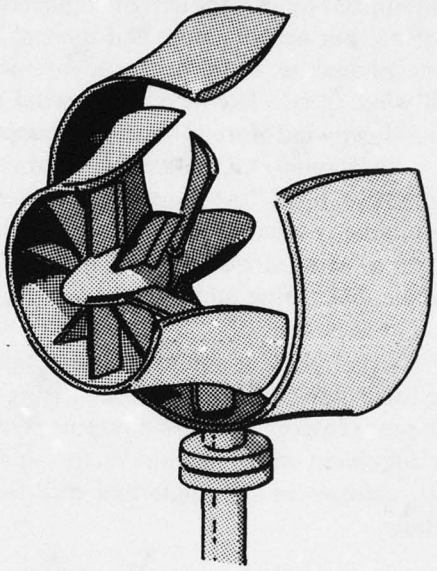
Gravitational forces cause lead-lag bending stresses in large-diameter horizontal-axis turbines, but their effects on most vertical-axis turbines, other than structural loading, have not been fully analyzed and reported.

One type of vertical-axis wind turbine under study, the Giromill, uses variable-pitch blades that are flared from a positive to a negative angle of attack.[9] In this concept, the aerodynamic lift force and centrifugal force will alternately reinforce and counter each other during each revolution of a blade, causing abrupt changes in the blade-bending stresses. The severity of the problem has not been fully analyzed, but will depend in part on the abruptness of the blade flips. Another type of vertical axis wind turbine being studied is the "Circulation Controlled Panemone." In this concept, air is blown over the turbine blade to control its circulation. This has an effect similar to varying the pitch of the blades, but without moving any part of the blade.

TURBINE AUGMENTATION

The blades of the wind turbine rotor represent one of the major cost elements; the economics of scaling to larger-diameter turbines have not been fully explored, and they cannot be until the design problems related to aerodynamic and rotational forces in larger systems are solved. Therefore, if a relatively inexpensive method can be devised to increase the energy density of the wind, considerable economic benefits may be realized. Augmentation studies have centered on two primary concepts: shrouding and vortex generation. Another augmented system being investigated is the dynamic inducer concept. The shrouded system has been tested, but the other systems have not, other than wind-tunnel studies of small models.

Shrouding consists of constructing a circular tube around the turbine, with the turbine located near the narrowest diameter. A ball-shaped intake and conical tail diffuser complete the device. A diffuser may be used alone without any shrouding before the turbine. The axial wind velocity is increased in the throat, thus increasing the power density, or augmenting the turbine. Decreasing the turbine size with respect to the diffuser increases the system augmentation. Figure 11-7 illustrates a diffuser-augmented wind turbine concept.



Source: Frank R. Eldridge, ed., *Wind Workshop 2,* Proceedings of the Second Workshop on Wind Energy Conversion Systems, The Mitre Corporation, Washington, D.C., 9-11 June 1975, NSF-RA-N-75-050, MTR-6970.

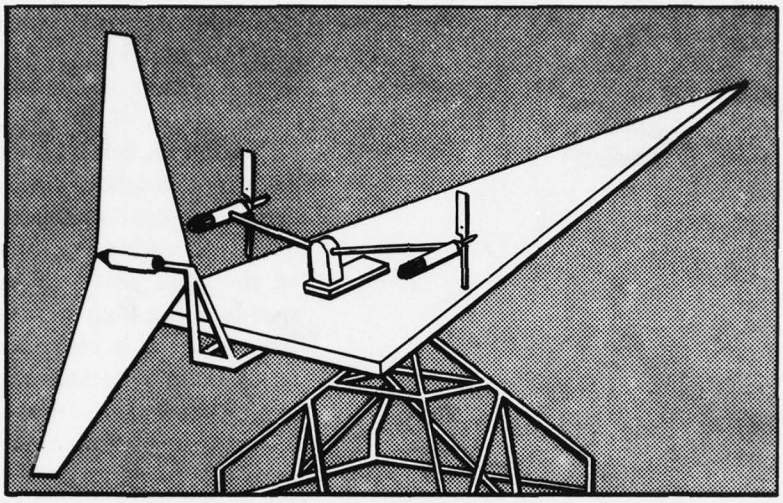
Figure 11-7. SHROUDED DIFFUSER AUGMENTED WIND TURBINE

Work on shrouded turbines, started in Great Britain during the 1950s, showed that diffuser-augmented turbines can produce as much as twice the power of unshrouded turbines of the same diameter.[10] Subsequent work performed in Israel showed that an augmentation ratio (power output of augmented system divided by that of an unaugmented system of the same rotor diameter) of up to 4 is possible.[11] In wind tunnel experiments conducted at Ben Gurion University in the Negev, Israel, power density was increased by as much as 3.5 times over an equivalent unshrouded turbine operating in the same free-flow velocity.[6] However, optimum shroud geometry requires an overall length-to-turbine diameter ratio of approximately 7 to 1, which would result in unwieldy, and probably cost-prohibitive, designs in large-scale applications. Since the main contributor to shroud length was the diffuser cone, follow-on investigations concentrated on replacing the cone with one or more circular airfoils.

Encouraging cost-effective studies of diffuser augmentation systems based on preliminary calculations of systems having length-to-turbine diameter ratios on the order of 4:1 were reported by Grumman Aerospace Corporation.[6] Grumman estimates that a diffuser

augmented system can be as much as 50 percent cheaper than a conventional wind energy conversion system for the same rated power.[12]

Vortex augmentation uses a wing or other aerodynamic shape to generate a vortex and places the wind turbine in the vortex where the wind energy density is highest. Wind tunnel experiments conducted at the Polytechnic Institute of New York have used delta-shaped surfaces (see Figure 11-8).[6] Results showed from two to nine times the power of an identical unaugmented turbine with 6 m/s winds, and an ability to run and carry a load at much lower velocities.



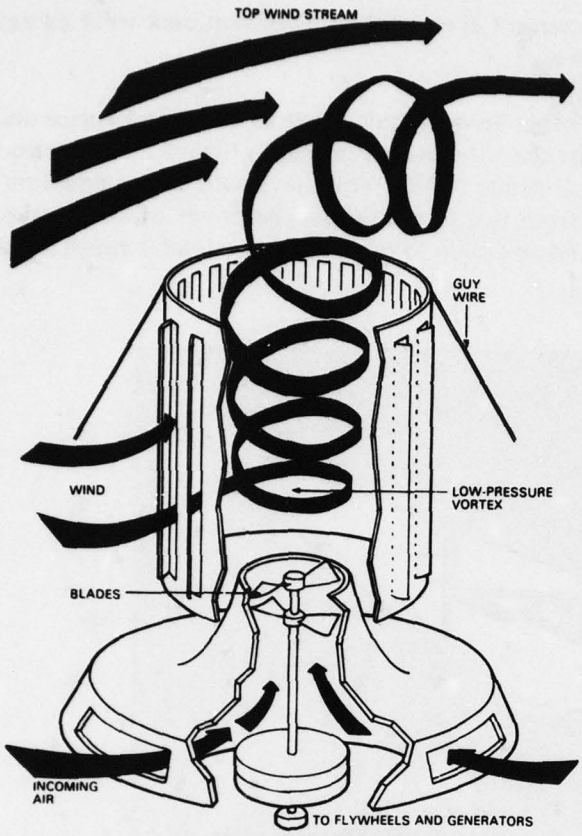
Source: U.S. Energy Research and Development Administration, "Vortex Augmentors for Wind Energy Conversion," E(49-18)-2358, December 1976.

Figure 11-8. VORTEX AUGMENTOR

Another study of vertical vortex augmentation has involved a tornado-type wind energy system, shown in Figure 11-9. The system uses a series of adjustable slots in a large vertical tower to create an internal vortex and a very low pressure drop, which provides a much larger power output than a conventional wind energy conversion system.[13] A full-scale prototype of such a system has yet to be tested.

ENERGY CONVERSION

Although in the earliest applications of wind energy there was direct mechanical coupling of wind turbine to the driven machinery or water pump, such applications severely limit site selection and system configuration, and are of limited potential today. Consequently, all large-scale experimental systems are designed to generate electricity. Although this is less efficient than direct mechanical drive, the advantages more than compensate for the energy conversion losses, particularly in energy transmission and storage. Compressed air conversion offers some of the advantages of electrical generation in that the compressor



Source: Ben Kocivar, "Tornado Turbine Reaps Power from a Whirlwind," *Popular Science,* January 1977.

Figure 11-9. TORNADO TURBINE

is relatively lightweight and can be mounted in the power head, and short-range energy transmission and storage are easily done. This concept is within technological capability, but has not yet been fully tested.

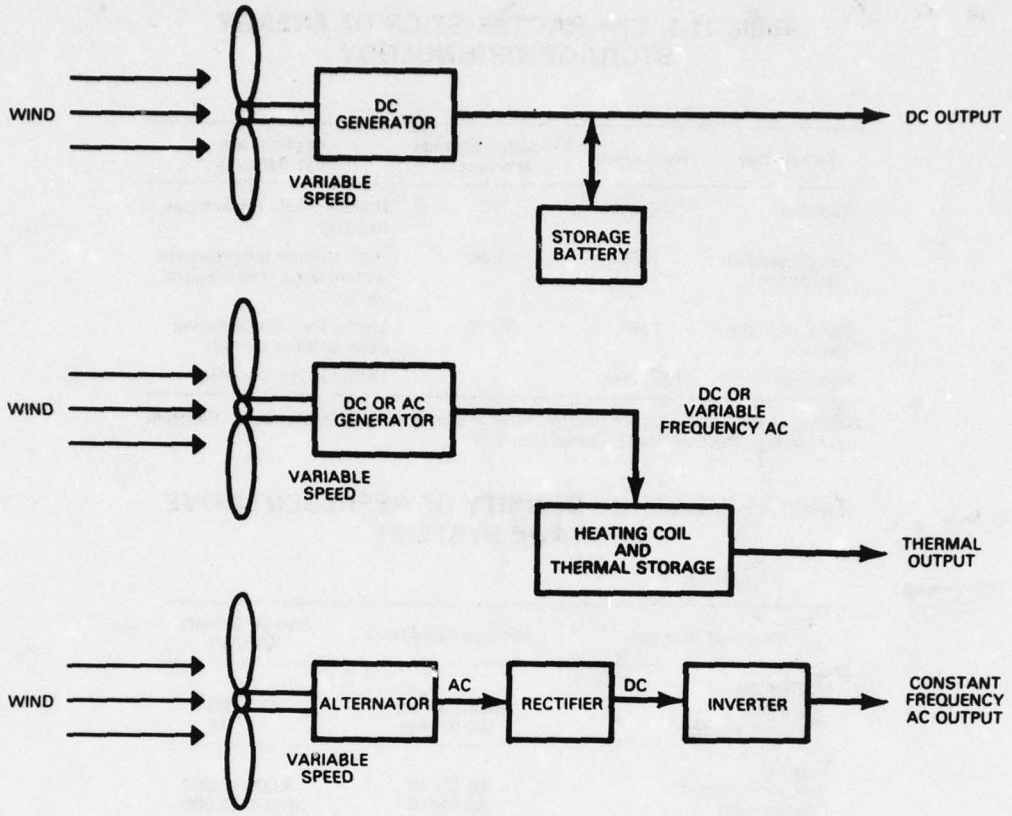
When electrical power is to be generated at remote sites or for local consumption not connected with a power grid, the system can be relatively simple. Either AC or DC may be generated as required. Figure 11-10 illustrates several system design schemes.

Even though high wind speeds give disproportionately high outputs, it is often not economical to design electrical generating equipment to absorb all the rotor power at maximum wind speeds. Since high winds occur only infrequently, it is more cost-effective to use a small generator that maintains a flat rating and, in most cases, does not seriously degrade overall system performance. Testimony presented before the House Subcommittee on Energy showed that, based on University of Oklahoma wind data, a generator of only half the size required to absorb the maximum wind turbine output will produce 90 percent of the total wind turbine power potential at the site.[14]

ENERGY STORAGE

Some source of supplementary energy must be available when wind speed is below turbine cut-off speed and when demand is greater than can be provided by the prevailing wind. An energy storage system may also take advantage of those periods when available wind-generated power exceeds demand. For remote sites, an energy storage and retrieval system is essential if the full potential of wind power is to be realized. In utility grid systems, energy storage is required in the utility system (not necessarily at each wind turbine) if wind energy penetration exceeds 10 to 20 percent of the utility capacity.

The most practical method of storage for a wind energy conversion system appears to be pumped hydropower. The preliminary results of one study indicate that wind power coupled with water power would add to the capacity of the local utility.[15] In such an opera-



Source: Frank R. Eldridge, ed., *Wind Workshop 2,* Proceedings of the Second Workshop on Wind Energy Conversion Systems, The Mitre Corporation, Washington, D.C., 9-11 June 1975, NSF-RA-N-75-050, MTR-6970.

Figure 11-10. METHODS TO CONVERT WIND ENERGY TO ELECTRICITY

tion, the wind units supply power to pump water from an auxiliary reservoir below the hydroelectric dam back into the main reservoir above the dam. The water stored in the main reservoir can then be used and replenished when the wind is blowing, adding to the capacity of the system to generate base-load electrical power.

When wind-generated power is used to supplement a power grid, the energy storage problem is reduced to the existing fuel storage problem; but in a self-sufficient wind-power system, excess energy must be stored when available and retrieved during periods of insufficient wind. Table 11-1 lists the characteristics of current storage techniques, and Table 11-2 compares the energy density of representative storage systems.

Table 11-1. CHARACTERISTICS OF ENERGY STORAGE TECHNOLOGY

Technology	Availability	Efficiency Storage (Percent)	Applications and Remarks
Batteries	1980-2000	70	Utilities—help replace gas turbines
Compressed-air (Adiabatic)	1985	70-80	High storage temperatures require large underground cavity
Pumped hydro-power	1985	70-75	Useful for utilities during peak-shaving periods
Flywheel	1990-2000	—	Useful in remote areas

Source: U.S. Department of Energy, Energy Storage Systems Division, "Program Overview," (Review Draft), December 1977.

Table 11-2. ENERGY DENSITY OF REPRESENTATIVE STORAGE SYSTEMS

Means of Storage	Storage Conditions		Energy Density (Btu/ft^3)
Mechanical			
Flywheel	Optimized steel		<43,000
Pumped storage	100 ft head		14
Thermal			
Hot rocks/metal	60-500°F		8,000-12,000
Molten salts	60-500°F		10,000-20,000
Steam	15 psi	212°F	40
	120 psi	347°F	340
	500 psi	467°F	1,270
Water	15 psi	212°F	9,000
	130 psi	347°F	16,000
	500 psi	467°F	21,000
Chemical			
Hydrogen			
Gas	15 psi	60°F	280
	1,000 psi	60°F	18,500
Liquid	15 psi	−425°F	200,000
Hydride (Mg_2Ni or FeTi)			250,000
Ammonia			340,000
Methanol			430,000
Gasoline			830,000
Batteries			10,000-80,000

Source: J. M. Savino, ed., *Wind Energy Conversion Systems,* Workshop Proceedings, 11-13 June 1973, NSF/RA/W-73-006, December 1973, PB-231-341.

RESEARCH AND DEVELOPMENT[16]

Wind energy conversion has long been recognized as a potentially abundant source of clean and renewable mechanical and electrical power. In 1973, the impending worldwide shortage of nonrenewable energy sources and the nation's increasing dependence upon imported fossil fuels led to a renewed effort to investigate the feasibility of converting the

wind into useful energy. The Department of Energy (DOE) is the primary agency involved in wind power research and development, which is focused on advancing technology for small and large wind systems, developing a sound industrial technology base, and addressing nontechnological issues that could alter the use of wind energy. To accomplish this end, DOE organized its federal wind energy program to promote the earliest possible commercialization of wind power by developing and assessing the technical, economic, and institutional requirements for the widespread use of wind energy conversion systems, while stimulating their commercial application.

DOE's wind energy program is organized into five discrete, yet interrelated parts: program development and technology, farm and rural (small) systems, 100 kW-scale systems, MW-scale systems, and large-scale multiunit systems. Information obtained from efforts undertaken within the program development and technology section is used widely in the research and development carried out within the other four sections of the wind energy program.

Program development and technology involves defining national and regional wind power potential; assessing and ameliorating potential environmental, legal, and social barriers to wind power; developing economical methods of determining the wind resource on a national, regional, and site-specific basis; and developing components and innovative wind systems to lower system costs and advance the state of the art. Specifically, this effort includes:

- *Mission analysis.* Current efforts include refining estimates of market potential for wind systems in isolated and remote areas and providing strategies for their development; identifying appropriate and effective government incentives for commercialization of wind energy conversion systems, identifying their costs and effects, and describing their potential implementation.
- *Wind energy applications.* Efforts are directed toward analyzing regional applications of wind energy within the United States and determining user requirements, wind resource, cost and cost sensitivity, and system performance and user interface requirements; handling control and stability characteristics of wind energy conversion systems; and designing safe and economical wind systems.
- *Legal/social/environmental issues.* Within the objective of addressing social and environmental effects of widespread use of wind systems; legal and regulatory issues; and public response to the utilization of systems and questions of aesthetics and land-use, current efforts are aimed at determining the effects of wind turbines on microwave and television signals, defining attitudes of users and owners of small wind energy conversion systems, and obtaining suggestions for the manufacture and marketing of such systems.
- *Wind characteristics.* In the attempt to economically locate and evaluate good sites for the various classes of wind systems as well as provide wind system design requirements, current projects are focused on determining the influence of topography on wind speed and turbulence; determining the feasibility of using wind deformation of vegetation as an indicator of mean wind velocity and of identifying high-wind sites from satellite imagery; assessing the potential for wind power development in Alaska and along the coastal zone (Maine to Texas); and providing

techniques for estimating wind characteristics at a site using data from other locations.

- *Technology development.* Projects and studies are directed at developing technologies required to reduce costs, improve system performance and reliability, and increase service life of both entire systems and individual components.
- *Advanced and innovative systems.* Projects and studies are directed at determining the technical and economic feasibility of alternative or innovative concepts and wind system configurations, such as the 17 m prototype Darrieus vertical-axis wind turbine being developed and tested by Sandia Laboratories. Other projects in this program are being managed by the Solar Energy Research Institute (SERI) in Golden, Colorado. DOE projects in advanced and innovative systems are listed in Table 11-3.

Table 11-3. ADVANCED AND INNOVATIVE WIND ENERGY CONVERSION SYSTEMS

Organization	Project	Contribution
Polytechnic Institute of New York	Vortex Augmentors for Wind Energy Conversion	Demonstrate and determine the potential of the delta wing vortex device for improved performance per unit cost over conventional systems.
West Virginia University	Innovative Wind Turbines	Determine the cost and performance benefits of a vertical-axis device featuring circulation control of the airflow.
Marks Polarized Corporation	Tests and Devices for Wind/Electric Power Charged Aerosol Generator	Characterize five methods of producing charged particles for electrofluid dynamic wind power generators.
University of Dayton	Electrofluid Dynamic Wind Generator	Develop a practical configuration for the generator and determine its performance and economics.
Grumman Aerospace Corporation	Diffuser-Augmented Wind Turbine	Refine a diffuser design developed under previous efforts and provide data to allow assessment of the design's potential cost benefits.
	Tornado-Type Wind Turbine	Test the tornado-type wind turbine to establish the feasibility of the concept.
Sandia Laboratories	Vertical-Axis Wind Turbine Program	Determine the feasibility of Darrieus vertical-axis wind turbines with blades of the troposkein ("turning rope") configuration.
McDonnell Douglas Aircraft Company	Giromill Wind Tunnel Test and Evaluation	Test the giromill windmill to determine cost-effectiveness.
University of Dayton Research	Madaras Rotor Power Plant	Determine the engineering and economic feasibility of the Madaras power plant.

Sources: U.S. Department of Energy, "Federal Wind Energy Program, Program Summary," DOE/ET-0023/1, January 1978, and U.S. Energy Research and Development Administration, "Federal Wind Energy Program, Summary Report," ERDA-77-32, January 1977.

DOE's program development and technology effort facilitates the development of farm and rural use (small) systems, 100 kW-scale systems, MW-scale systems, and large-multiunit systems for testing in promising applications.

The objectives of the farm and rural (small) systems section are to identify and test applications of small wind systems, assess the performance of available small wind turbines

for these applications, identify small machine development needs, and develop and evaluate advanced small wind turbines. The Rocky Flats facility in Golden, Colorado, operates a center for testing small wind systems and coordinates the development of advanced, small wind energy systems by private industry contractors. Advanced 1 kW, 8 kW, and 40 kW wind energy systems are being developed; eventually each system will be subjected to rigorous performance testing at Rocky Flats.

Efforts undertaken within the 100 kW-scale systems' section are directed toward the development of intermediate-sized wind systems for application to irrigation and small-scale industrial and utility uses and to support the development of larger systems. This work is being conducted by the NASA/Lewis Research Center and includes work on the 100 kW machine at NASA/Lewis Research Center, as well as the four 200 kW units being tested at utility sites.

The objective of the MW-scale system section is to develop durable and economical large systems for eventual use by large power producers, such as the electric utility systems. Several large wind turbines will be developed and tested to verify that energy costs decrease as the systems increase in size. A 61 m diameter, 2 MW machine will be tested near Boone, North Carolina, in 1979. (This unit will be the largest wind turbine built to date.) A 91 m turbine of 2.5 MW rating is presently being designed.

Systems showing promise for large-scale power production will be developed further for use in large-scale multiunit systems. The objectives of the large-scale multiunit systems section are to study the technical and economic requirements of operating several MW-scale wind machines as a system and demonstrate how wind energy systems could supply a considerable percentage of an electric utility system's generating capacity. To lay the groundwork for potential commercialization and mass production of wind systems, the program is designed to involve private industry at every stage in the development and fabrication of wind systems and to solicit the participation of potential users in applications studies, field tests, and other commercialization-oriented activities.

Two U.S. private industry efforts to develop large wind machines have been initiated without federal funding. WTG, Inc., has built a 24 m diameter three-bladed unit at Cuttyhunk Island, Massachusetts, for $280,000. It develops 175 kW at 12.5 m/s. Another large machine has been developed by Charles Schachle. It has a three-bladed rotor, runs at a constant tip-speed ratio, rather than at constant rpm, for high efficiency, and uses a hydraulic system instead of mechanical gears to link the wind turbine rotor to the electric generator. A 22 m diameter version has been tested, and a 50 m diameter machine, rated at 3 MW at 18 m/s,[7] will be erected in southern California this year at a cost of $1 million.[8]

International activities in wind energy include efforts in Canada, Denmark, Germany, New Zealand, the Netherlands, Sweden, France, the United Kingdom, Japan, Israel, Australia, Switzerland, and the USSR. A 200 kW Darrieus wind turbine, installed on the Magdalen Islands in the Gulf of St. Lawrence by the National Research Council of Canada, is the largest vertical-axis wind machine ever built.[8] A 54 m diameter, three-bladed windmill was built by members of a college community in Denmark with no government sponsorship.[17] The power of this machine is rated at 2 MW; the estimated cost is $720,000.

ECONOMICS

With the exception of hydropower, wind power is the cheapest source of electricity from inexhaustible energy supplies today.[8] The 200 kW machine at Clayton, New Mexico, delivers electric power to the local utility at about $0.20/kWh. The 2 MW machine scheduled to become operational in 1979 at Boone, North Carolina, will provide power at about $0.10/kWh. Future machines should provide power at about $0.05/kWh, and still lower prices (as low as $0.02/kWh) are predicted for mass-produced large machines.[1]

The DOE wind program's cost goals are illustrated for large and small wind machines in Table 11-4.[4]

Table 11-4. DOE COST GOALS FOR WIND MACHINES

Type	Specifications			
	Capital Cost ($/kW)	Energy Cost (Mill/kWh)[a]	Size (kW)	Wind Speed (Average m/s)
Large wind machines				
Mod 2 (1980)				
Initial unit	1,500	70	2,000	6.3
Mature unit	750	30	2,000	6.3
Advanced (1985 design)				
Initial unit	600-900	20-30	2,000-4,000	6.3
Mature unit	400-600	10-20	2,000-4,000	6.3
Small wind machines				
Currently available				
Initial unit	2,000	100-200	1	6.3
Mature unit	1,300	50-100	1	6.3
Advanced (1985 design)				
Initial unit	1,200	40-80	8	5.4
Mature unit	750	20-40	8	5.4

[a]Excludes demand charges, which small users might be required to pay for electric utility backup power.

Source: U.S. Department of Energy, "Solar Energy, A Status Report," DOE/ET-0062, June 1978.

ENVIRONMENTAL, LEGAL, AND INSTITUTIONAL ISSUES

Wind energy systems have few physical effects on the environment; wind systems do not pollute air or water or produce solid waste. Structural safety and electromagnetic radiation interference are of concern, however.[18] Among potential safety hazards are those associated with structural failure, electric transmission equipment, and construction or maintenance of towers or tower-mounted equipment. For example, although an unlikely occurrence, a thrown blade could travel a distance of 150 m.

Electromagnetic radiation interference may occur when reflected signals from moving rotor blades interact with the original signals—television, navigational aids, and microwaves, for example. Preliminary studies indicate that reception difficulties could occur up to 5 km away.

Another environmental concern is that towers and rotors can be hazardous to birds, especially at night or when visibility is poor. Birds have been observed to avoid flying through the rotor disk of the NASA/Lewis Research Center wind turbine.

Socioeconomic concerns include public acceptance. The physical appearance of wind structures, particularly in scenic areas, could become a barrier to public acceptance of wind energy systems. The impact will depend on the size and character of the turbines, the scenic character of the site, and the degree of visibility in populated areas. Additional potential issues are operational noise and offshore emplacement.

Integrating wind energy systems with existing, conventional electric utility systems is a key institutional issue. Modification of rate structures may be necessary.[19]

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12. ENERGY FROM BIOMASS

Biomass conversion, or bioconversion, is the process of transforming solar energy captured by photosynthesis into gaseous, liquid, or solid fuels to provide heat and electricity. Biomass suitable for conversion into energy is available from three major sources: trees and plants grown specifically for use as an input for energy production, plant and animal residues, and urban and industrial wastes (municipal solid residues).

Use of biomass for energy varies in different areas of the world, depending in part on the level of development of the countries. In the United States, for example, biomass conversion amounts to about 1 percent of the U.S. energy supply, while in Sudan it accounts for as much as 65 percent. In many underdeveloped countries with low per capita energy consumption, biomass provides most of the basic energy needs. Biomass energy conversion has the best chances of becoming an important energy source among tropical countries with large quantities of land not yet fully utilized.[1]

Biomass, a renewable resource, not only provides a nonpolluting low-sulfur fuel and, in some situations, an inexpensive source of energy (for example, wood fuel, dry animal manure, methane gas, alcohol), but also couples production of fuels from biomass to the synthesis of protein. Theoretically, bioconversion techniques simultaneously can solve, or at least minimize, waste disposal and the attendant pollution problems while providing solid supplemental fuel or new conversion products—liquid or gaseous fuels, sugar, protein, and fertilizer.

Major difficulties associated with converting biomass to energy are the relatively small percentage (less than 0.1 percent) of light energy converted into biomass by plants, the relatively sparse and low concentration of biomass per unit area of land and water, the scarcity of additional land suitable for growing plants, and the high moisture content (50 to 95 percent) of biomass that makes collection and transport expensive and energy conversion relatively inefficient. All of these factors make biomass energy costly in terms of energy invested in the conversion process and reduce the net energy yield.[1] In general, bioconversion efficiencies are very low. The most productive systems (sugarcane) have net conversion efficiencies in excess of only 3 percent; a system using euphorbia, which is a class of plants closely related to the rubber tree and produces a hydrocarbon somewhat similar to petroleum, would have a conversion efficiency of about 0.5 percent.

BIOMASS RESOURCES

Estimates of the size of the biomass resource in the United States vary because of different estimates on recoverable crop and forest residue, the acreage and density of biomass, the resource potential for producing biomass as a primary energy feedstock, and the energy

content of the biomass itself. The contribution of biomass as an energy source currently is minimal. By the end of the century, however, biomass is expected to contribute about 7 quadrillion Btu/year, or about 10 percent of the current U.S. energy consumption of 75 quads.

Two factors are predominant in evaluating the biomass energy potential: use of silviculture, agriculture, or aquaculture as a primary means of producing energy feedstocks; and the potential of energy from plant, animal, and municipal solid residues (MSR). Trees are the most identifiable and readily available biomass in the United States, but other forms of land-based and aquatic biomass eventually may be cheaper or more desirable for various reasons.[2] The energy plantation concept together with forestry, agricultural, animal, and municipal residues offer a potential source of a perpetually renewable low-sulfur, low-nitrogen fuel that could be used to relieve U.S. dependence on foreign oil and gas supplies.[1]

Silvicultural and Agricultural Biomass

Forestry is particularly suitable for biomass energy production because: the energy harvest per acre can be many times that for annual crops, wood is a dense storable form of biomass fuel, trees grow productively for many years and thus provide live storage from year to year without loss of yield, nutrient losses in forestry are relatively small, and wood fuel is relatively clean-burning.[3] The U.S. Forest Service estimates that national timber resources occupy 730 million acres, concentrated mainly in the southeastern and northwestern areas of the United States, and could yield about 300 quads of energy in terms of immediately usable heat. This is about the same energy available in proved natural gas reserves (290 quads), about a third more than in the proved oil reserves (200 quads), and less than 10 percent of the potential heat energy in the proved coal reserves (over 4,000 quads).[2] Forest biomass harvested in the United States annually is equivalent to 5.7 quads of energy. Only 2.9 quads of this biomass is used to produce lumber, pulp/paper, and fuel; the remaining 2.8 quads—the equivalent of almost 1.5 million bbl of oil/day—is not used.[1]

Unlike other hydrocarbon fuel sources, timber is renewable in the short term, varying from about 25 years in the southeastern United States to 100 years in the Northwest. Much of the interest in trees as biomass derives from the renewal rates, equivalent to about 7.5 quads/year. The U.S. Department of Energy (DOE) estimates that about 6.5 million acres of trees (whatever the species) are necessary to supply 1 quad/year of usable energy, and as an interim goal, suggests that 30 million acres (10 percent of the available acreage) be planted in the next 10 to 15 years to supply trees as biomass.[2]

In addition to biomass itself, multiple-use materials may come from forests. A study at the University of Georgia suggests that a revitalized chemical industry and fuel industry may be possible based on oleoresins (naval stores, gum resins). With improvements in planting, present acreage, if devoted to fuels, could produce annually the energy equivalent in oleoresins of more than 3 percent of national imports and eventually as much as 30 percent of that import demand. An attractive feature of the oleoresin potential is that once the trees have passed their resin production peak, they are still available for harvesting as wood biomass. Although oleoresin extraction makes much of the southeastern U.S. pine crop twice as valuable as a fuel source, the optimum use of oleoresins would require considerable technical effort to provide the necessary chemical conversion facilities beyond combustion.[2]

Short rotation forestry is one of the promising management systems for producing biomass for energy. In recent silvicultural studies, the United States and Canada successfully have selected and tested faster growing trees of several species. Eucalyptus, sycamore, red alder, and poplar comprise the chief tree species being considered by DOE. Other research efforts focus on increasing the oleoresinous content of pine trees, using chemical injections to stimulate the growth rate of trees, and developing improved techniques for harvesting and processing trees and forest residues.[4] Some success has been obtained with on-site chipping of wood biomass to reduce costs of collection.[2]

Another concept for producing energy from biomass is the energy plantation in which crops such as sugarcane, sugar beet, sweet sorghum, and kenaf would be grown entirely for producing fuel. Sugarcane, an unusually high-yield plant, has great potential as a biomass source for energy conversion. However, experience in agriculture shows that a prerequisite for high crop yield is high energy input to production.[3] DOE is supporting studies for refining species selection and developing crop management technology to maximize crop yields while minimizing production costs.[5] For land-based biomass, improvement in species by genetic manipulation has not been tried in the field, although there have been promising experiments with some types of grasses, sorghum, and cane.[2]

Estimates indicate that an area less than one-third of that involved in farming in the United States could meet the entire energy requirement of all the installed electric generating capacity in the country.[1] Assuming production of 25 tons of combustible material per acre, about 96 million acres of land (roughly 20 percent of the total arable land in the United States) would be required to produce one-half of the natural gas demand in the United States. A major problem, however, is the availability of water. As a general rule, about 500 tons of water are required to produce a single ton of dry plant matter. To obtain a yield of 10 dry tons/acre-year, 44 inches of rain (or its equivalent as irrigation) must be provided. For comparison, rainfall over the southeastern United States averages 48 inches per year.

Because of the requirements for water in biomass production, fresh water and ocean farming concepts have been proposed, and numerous aquaculture projects currently are being examined to determine their feasibility. National Aeronautics and Space Administration (NASA) researchers have found that 7 pounds of water hyacinths can produce about 7 cubic feet of natural gas. Research results indicate that cultivation of water hyacinths in the southeastern United States could produce 60 dry tons/acre-year. Production of 72 billion scf/year of methane from water hyacinths would require 25,750 km of canals on 222,000 acres of land. Hyacinths also can be used for food and fertilizer after they have been used to remove impurities from waste water for conversion to synthetic natural gas.[6] Other experimental results indicate that single-cell algae in nutrient-rich fresh water exhibit growth rates as high as 70 dry tons/acre-year, with 16 to 32 dry tons/acre-year reasonable for a 365 day growing season.

The ocean offers five to 10 times more area with potential for biomass cultivation than the land, but almost none of this ocean area is under systematic cultivation. One square mile of ocean has a potential of fulfilling the energy needs of over 300 people at the U.S. energy consumption level.[7] Studies of giant California kelp, which grows along the coast of California, Mexico, and New Zealand, indicate that, at a spacing of 10 feet per plant, an acre of

ocean could yield 200 to 500 wet tons of harvested organic material per year (equivalent to about 400 million Btu of energy, assuming a 2 percent conversion efficiency under proper growing conditions). A General Electric Company project is under way to grow giant California kelp in a one-quarter acre farm 5 miles off Laguna Beach, California; the harvested kelp (about 114 tons/acre-year) will be anaerobically digested to produce methane (about 100,000 scf/acre-year) and by-products.[8]

Plant and Animal Residues

Plant and animal residues are valuable energy sources. Waste wood in U.S. forests amounts to over 500 million dry tons/year, and culls, slash, and logging residues amount to about 3 billion dry ton/year. Residues produced annually from crops, such as small grains, grasses, rice straw, corn, and sorghums, amount to an estimated 390 million dry tons. These residues, which are produced in a concentrated form, could be processed readily and could supply about 5 percent of total U.S. energy needs.[1,9] The energy potential of forest and crop residues is about 3 quads, equating to over 1.5 million bbl of oil/day or $7 billion/year. The energy potential of most forestry and agricultural biomass is unlikely to exceed 3 quads because the value of standing forest and existing crops as paper, timber, and food far outweighs their potential energy value.[1] Also, biomass conversion of agricultural and forestry residues has not been economically attractive because of the expense of collecting and transporting the residues and because their heat contents are relatively low (compared with MSR) due to their high moisture contents. Advances in equipment and technology development are contributing to the solution of such problems;[1] additionally, some innovative approaches are being taken. For example, Burlington, Vermont, plans to construct a 50 MW generating plant fueled entirely with wood chips from trees culled from Vermont's 4 million acres of forest; voters have approved the sale of $40 million in bonds to cover one-half the cost of the facility.

Another important source of biomass is manure from animals, generally feedlot cattle, swine, sheep, and poultry. Bioconversion of animal manure produces two useful products: a residue that is an excellent fertilizer and a medium-Btu gas that can be used more efficiently and is more environmentally acceptable than direct combustion of animal and agricultural residuals. In India, the total amount of gas that can be produced from dung and night soil is equivalent to 930 million tons of coal or about 4 billion bbl of oil.

Municipal Solid Residues

MSR generated by large metropolitan areas could supply over 1 percent of total U.S. energy needs.[9] The quantity and heating value of these residues are large, and the dry and combustible fraction of solid residue, equivalent to 910 million bbl of oil in the early 1970s, could increase to the equivalent of 1.5 trillion bbl of oil by 1990.[10] The Environmental Protection Agency (EPA) has shown that an estimated 138 million tons of municipal and rural solid residues were disposed of in the United States in 1975, amounting to about 3.2 lb/day/person. MSR amounted to about 94 million tons (see Table 12-1), and about 7.8 million tons were recycled. (Rural residues are not shown because of the expense of collecting them.)

Table 12-1. MUNICIPAL SOLID RESIDUES

Category	1975 Tonnage (Millions)	Percentage in Total Waste[a]
Combustible		
Paper	27.3	29.0
Plastic	3.2	3.4
Rubber and leather	2.4	2.6
Textiles	1.5	1.6
Wood	3.6	3.8
Food	16.7	17.8
Yard residue	19.0	20.2
Noncombustible		
Glass	9.8	10.4
Ferrous metals	8.1	8.6
Aluminum	0.7	0.7
Other nonferrous metals	0.3	0.3
Miscellaneous inorganics	1.4	1.5
Total	94.0	99.9

[a]Figures are as-generated wet weight, as disposed figures have higher moisture that alters the percentages and raises the total weight. Column does not add to 100 due to rounding.

Source: J. F. Bernheisel, "Energy From Urban Waste," *Energy Technology V, Challenges to Technology* (Washington, D.C.: Government Institutes, Inc., 1978).

The composition and quantity of available MSR vary, depending on season, location, and socioeconomic factors. The energy contained in as-received MSR is about 4,500 Btu/lb, which amounted to a potential of 846 trillion Btu available in 1975. This energy is concentrated in the combustible portion of MSR, amounting to a heating value of about 5,740 Btu/lb of combustible material. On a moisture- and ash-free basis, the heating value of as-received MSR is 8,000 to 9,000 Btu/lb. However, the amount of energy recovered depends on the processing or combustion system used. Net conversion efficiencies estimated for nine systems ranged from 37 to 70 percent. Based on these percentages, the realizable energy potential in 1975 from the combustible materials in MSR averaged about 453 trillion Btu/year. Adding the energy savings from materials recovery to this amount resulted in a total potential energy savings of 923 trillion Btu in 1975 from MSR.[11]

MSR disposal sites are untapped sources of methane gas. Landfill gas, mainly produced during anaerobic decomposition of organic waste material, contains 40 to 60 percent by volume methane, as well as varying amounts of carbon dioxide, nitrogen, and hydrogen sulfide. The heating value of raw landfill gas is about 450 Btu/scf. Depending on final use, landfill gas can be compressed, dehydrated, and stripped of carbon dioxide and nitrogen to produce a gas with a heating value ranging from 650 to 1,000 Btu/scf.

The amount of gas recoverable from landfills depends on the ultimate gas production (scf/pound of solid residue) and the area-depth relationship. Estimates of ultimate gas production values range from 0.05 to 7.0 scf/pound of solid residue, based on lysimeter studies conducted at optimal conditions and on addition of sewage sludge to MSR. If air infiltrates into the landfill, methane production ceases or declines to a level where the methane content of the raw gas is too low for economical recovery. Because of the possibility of air infiltration, a deeper landfill is preferred to a shallow landfill, even though volume is constant. The amount of gas recoverable at a site also depends upon the specifics of site construction and the operational aspects of a gas recovery system. Site geology is important because it can permit containment of the landfill gas. A landfill located in a clay formation or lined with a clay or synthetic material will inhibit the movement of landfill gas from the site and thus increase the potential for gas recovery.[1]

Landfill gas recovery and purification is a proved, economically feasible means of energy recovery from solid waste, provided the necessary combination of technical expertise

and financial backing is available. Reserve Synthetic Fuels, Inc., one of the first companies to recover methane from landfills, operates such a system in southern California, collecting gas that is 50 to 56 volume percent methane, 40 to 45 percent carbon dioxide, and 0.5 to 1 percent trace contaminants. After the gas is treated, the methane (99 percent pure) is metered into the Southern California Gas Company distribution system.[12] Reserve Synthetic Fuels and Getty Synthetic Fuels, Inc., plan to build a methane recovery and purification plant at one of the world's largest sanitary landfills in Monterey Park, California. The plant, to be completed in late 1979, is expected to recover about 8 million cubic feet (MMcf)/day of raw landfill gas from about 23 million tons of refuse through a series of underground wells 90 m deep. The gas, after processing, will feed into the Southern California Gas Company system. In Sun Valley, California, methane gas recovery from a refuse landfill is expected to provide enough fuel to generate 28,000 MWh of electricity a year at a Los Angeles city power plant. The landfill, containing 6 million tons of refuse, is expected to produce a billion cubic feet of gas annually during its first 10 years of operation. The gas will be recovered through 14 wells and moved through 3 km of gas pipeline to the generating station.[13]

BIOCONVERSION TECHNOLOGY

Bioconversion processes available or under development include direct firing of either raw or shredded biomass feedstocks in heat recovery boilers or waterwall combustion units to produce steam, as well as microbiological or thermochemical conversion of biomass feedstocks to produce various intermediate solid, liquid, or gaseous fuel products for on-site use or for sale to customers. Microbiological or thermochemical conversion of biomass yields end products that have more energy content than does the biomass. The additional energy content per unit weight arises from loss of oxygen and carbon dioxide and from formation of energy-rich carbon-carbon double bonds or ring structures. In some cases, advantages in energy content may be small but the liquid or gaseous fuel produced may be more convenient to transport and store than the raw biomass.[14]

Much of the current process development work focuses on improving operating conditions, product yields, and overall system efficiencies of processes that have been known for many years. New residue-to-energy plants are coming on-line to add to those in commercial use, and many projects aimed at advanced biomass and residue conversion processes are being developed. DOE's R&D efforts on fuel from biomass focus on developing capabilities for converting renewable biomass resources into clean fuels, petrochemical substitutes, and other energy-intensive products that can supplement products made from conventional fossil fuels.[15]

Several small- and moderate-scale biomass production projects now are in the field-test stage, and integrated biomass production-conversion systems in which the biomass is grown specifically for energy production or manufacture of synthetic fuels are expected to reach this stage by 1980.[1] Of 132 pilot, demonstration, and commercial plants for converting biomass in the United States, 39 are devoted to direct combustion of biomass, 24 to anaerobic digestion, 26 to separation of municipal residues for further treatment, and the remainder to a variety of lesser-volume jobs. Only four focus on ethanol production, although this product appears to be one of the first to enjoy success in the immediate future.[2] Direct combus-

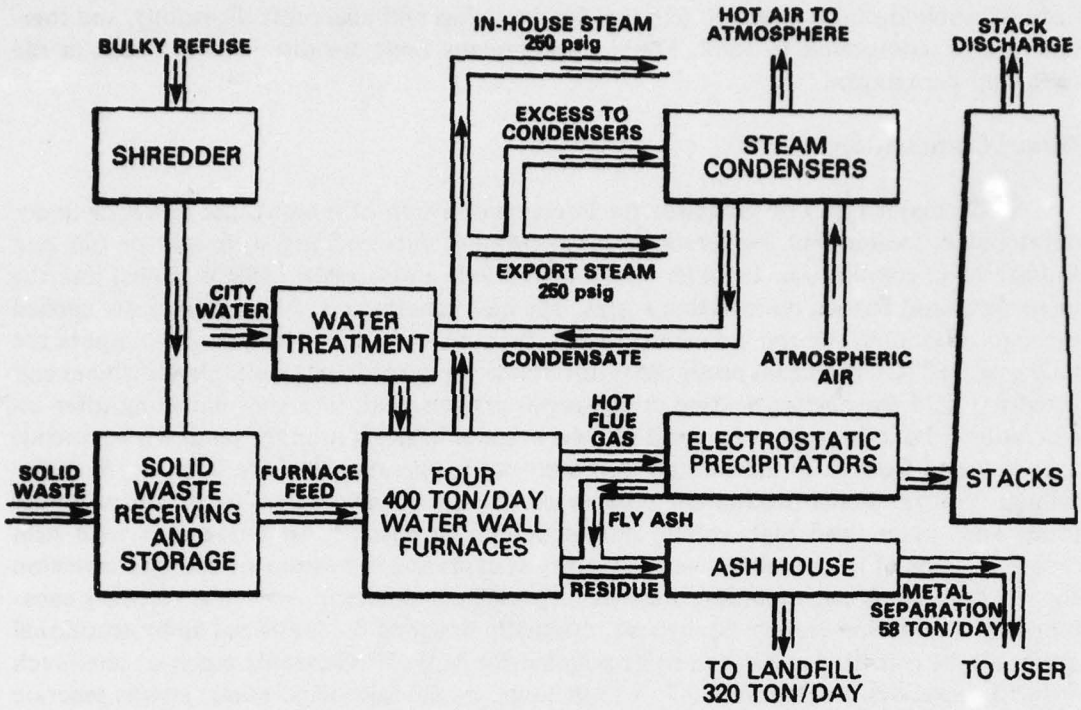
tion, microbiological conversion (ethanol fermentation and anaerobic digestion), and thermochemical conversion to solid, liquid, and gaseous fuels are discussed in detail in the following paragraphs.

Direct Combustion

Three major types of processes for direct combustion of biomass are in use or under development: water-wall incineration, supplementary fuel cofiring with coal or oil, and fluidized-bed combustion. In water-wall incineration, unprocessed MSR is loaded into the incinerator and burned on traveling grates. The heat generated is collected by water carried through tubes that line the incinerator walls. Because of its low pressure and temperature (600 psig, 260°C), the steam produced is unsuitable for use in large power plant turbines and usually is sold for district heating or industrial process heat. The ash remaining after incineration (about 20 percent by weight of the original MSR) is used for landfill after metals are separated from it. Disadvantages of water-wall incineration include difficulty in maintaining uniform steam production because of uneven burning rates, corrosion on boiler tubes and grates, and high capital and maintenance costs.[16] An incinerator with heat recovery is one of the simplest energy recovery systems and is a means of energy conversion for relatively small communities. Small-scale package incinerators with heat recovery capabilities and pollution control equipment, originally designed for industrial and institutional applications, recently have begun to be adapted for MSR.[7,17] Generally batch or semibatch fed with capacities ranging from 0.1 to 5 ton/hour, small-scale incineration systems generate 1,000 to 5,000 lb/hour of saturated steam. Large-scale systems process up to 2,000 ton/day of residue to produce either saturated or supersaturated steam; a 1,000 ton/day unit would produce about 240,000 lb/hour (on a 24-hour basis) of saturated steam.

Over 200 large-scale residue-to-energy units are operating in Europe, and several (including the Chicago Northwest Incinerator, operating commercially since 1971, and a unit in Saugus, Massachusetts) have been built in the United States using European proprietary systems.[11] The Chicago Northwest Incinerator (see Figure 12-1) uses four 400 ton/day water-wall furnaces to burn unprepared refuse at about 800°C. Each of these furnaces produces 110,000 lb/hour of 250 psig steam, most of which is condensed in air-cooled condensers. The Saugus unit, a privately owned facility completed in 1975, processes 1,200 ton/day of unsorted and unshredded MSR. This unit was the first U.S. plant to supply superheated steam (about 350,000 lb/hour of 625 psig steam at 425°C) to an industrial user on a commercial scale for power generation and process heat applications, saving about 14 million gallons of fuel per year. Other examples of water-wall incinerators in the United States include the Navy's facility at Norfolk, Virginia, operating since 1967 with no shredding capability, and the Harrisburg, Pennsylvania, facility, which incinerates 550 ton/day of MSR in two water-wall furnaces to generate steam for the Pennsylvania Power and Light Company. The Nashville Thermal Transfer Corporation facility burns 720 ton/day of MSR to produce steam for heating and cooling buildings in Nashville, Tennessee. (This facility was originally built shortcutting proved design criteria; however, it has been upgraded to correct design deficiencies and now is producing steam to design standards.)[7]

Burning biomass as a supplementary fuel in combination with steam-electric production is a proved and established technology in the United States. Many existing steam-electric



Source: J. F. Bernheisel, "Energy From Urban Waste," *Energy Technology V, Challenges to Technology* (Washington, D.C.: Government Institutes, Inc., 1978).

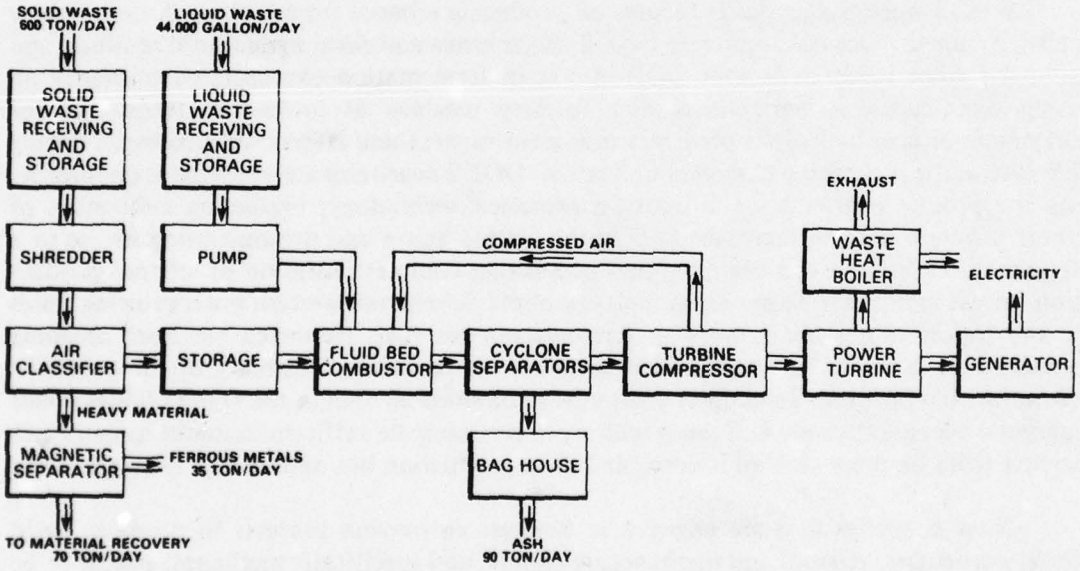
Figure 12-1. CHICAGO NORTHWEST INCINERATOR

production plants are designed to burn fossil and nonfossil fuels either simultaneously or separately. For example, pulp and paper mills generate their own power by burning 46 percent wood-derived fuels and 54 percent fossil fuels; forest product mills burn 98 percent wood fuels and 2 percent fossil fuels.[1] Since 1951, the University of Oregon has been burning wood residues from nearby mills to generate about 60 percent of its electrical needs and using the exhaust steam to supply energy for all of its heating and cooling requirements;[18] plans are under way to use refuse-derived fuel from MSR for cofiring in the University of Oregon facility. Most of the sugar mills in Louisiana and all of the sugar plantations in Hawaii burn bagasse (the plant residue left after cutting, spraying, squeezing, and milling of sugarcane, including some leaves and dirt) to generate steam and electricity for their process operations. In 1975, the Hawaiian sugar industry produced about 18.2 trillion Btu, of which 14.2 trillion was from burning of bagasse, 0.4 trillion from leafy cane trash, 3.3 trillion from fuel oil, and 0.3 trillion from wood chips and nut shells.[8] Foster Wheeler Corporation, along with Lihue Plantation Company and Kauai Electric Company of Hawaii, plan to build a $25 million power plant on Kauai, Hawaii, and operate it using bagasse. The plant, which also will be able to burn leafy cane trash, wood chips, and prepared MSR, is expected to begin producing electricity by late 1980.[19]

Operating problems have occurred in many of the plants cofiring biomass with coal or oil, but these problems generally have not resulted in permanent shutdowns. Emissions re-

quirements probably have been the source of the most difficulty, and in recent years, R&D has focused on identifying potentially hazardous emissions, defining corrosion rates associated with cofiring, comparing process and environmental characteristics of cofiring residue with coal in tangentially fired boilers versus stoker-fired boilers, pelletizing residue and injecting it along with lump coal into an industrial sized stoker-fired boiler, cofiring the combustible fraction of MSR with fuel oil in existing oil-fired boilers, and cocombusting sewage sludge and MSR. Retrofitting control systems on existing plants has eliminated many of the environmental problems, and new plants are expected to meet environmental requirements.[1]

Fluidized-bed combustion of MSR has been under development by Combustion Power Company, Inc. (CPC), since 1967 with EPA support. The process uses air-classified MSR to fire a conventional gas turbine to produce electricity. CPC's CPU-400 combustion system consists of a fluidized-bed combustor that operates at 760°C and three stages of cyclone separators to remove particulates from the gas prior to its expansion through the turbines (see Figure 12-2). The turbine compressor provides combustion air and the whole system operates at about 60 psi of pressure. A 70 ton/day pilot plant, which also has been tested with wood residues and high-sulfur bituminous coal, is still in the developmental stage. The system has not performed as expected nor has sufficient reliability been demonstrated for a prototype plant. An advantage of the process is reduction of noxious gas emissions, but removing all particulates larger than 5 microns before the gas enters the turbine is a major problem. A 1,000 ton/day MSR plant is expected to generate 340 MWh of electrical energy.



Source: J. F. Bernheisel, "Energy From Urban Waste," *Energy Technology V, Challenges to Technology* (Washington, D.C.: Government Institutes, Inc., 1978).

Figure 12-2. CPU-400 PROCESS

Microbiological Conversion

Ethanol Fermentation

Fermentation is a well-known biochemical process used to produce alcohol fuels from biomass. Usable raw materials include sugarcane, sugar beets, molasses, and fruit juices as well as starchy (cereals and potatoes) or cellulosic (wood and residue sulfite liquor) materials. Ethanol can be produced by fermenting any carbohydrate, although starchy or cellulosic materials require a pretreatment step to hydrolyze the raw material to sugars. The hydrolysis may be catalyzed by mineral acids or enzymes.[20] A breakthrough was achieved in biomass conversion with the demonstration of a cellulose pretreatment process in which cellulose is dissolved from wood, leaving the lignin and thereby avoiding the problems of ligno-cellulose complexing; the treated cellulose can be converted to glucose in yields as high as 90 percent.[2]

Environmental conditions of the alcoholic fermentation vary somewhat, depending primarily on the strain of yeast used to convert the sugars to ethanol and carbon dioxide. Use of acidic conditions inhibits bacterial contaminants; the initial pH is in the range of 4.0 to 5.5. Suitable temperatures are about 20 to 30 °C. Normally, industrial alcoholic fermentation operates on a batch basis and is completed within 50 hours, with yields exceeding 90 percent of theoretical, based on fermentable sugars. Concentration of alcohol in the culture medium typically is 10 to 20 percent, but depends on the alcohol tolerance of the yeast.[20]

In the United States, R&D focuses on producing ethanol from carbohydrates in algae cultures, aquatic biomass, pretreated wood, sugar crops and corn, agricultural residues, and animal feedlot residues. Recent DOE efforts in fermentation concentrated primarily on using ligno-cellulosic agricultural and forestry residues as lower-cost feedstocks for enzymatic or acid hydrolysis processes that yield sugar; these efforts will accelerate during FY 1980 at the process development unit scale.[5] DOE's near-term activities focus on improving the process efficiency of current fermentation technology; evaluating cultivation of sweet sorghum over an increased area in the United States and demonstrating its use in a fermentation facility; and planning and supporting commercialization of ethanol production for use in liquid transportation fuels (gasohol). Several midwestern grain-growing states in the United States are promoting fermentation for fuel. Nebraska has been blending ethanol into gasoline for years and is studying the economic feasibility of the concept.[6] However, the potential net gain in energy from biomass alcohol in the United States seems marginal because the only U.S. crop with a production scale sufficient to make a significant impact from biomass alcohol is corn, and corn production has high energy requirements.[3]

Other countries also are engaged in biomass conversion projects to produce liquid fuels, particularly ethanol and methanol. Alcohols, and specifically methanol, appear to be the best renewable liquid fuel option for Canadian resources available in the near term.[1] Brazil's goal in its biomass energy program, probably the largest and most advanced in the world, is to supply about 20 percent of its transportation fuel needs by 1980 with ethanol from sugarcane. The 1980 goal is a total ethanol capacity of 1.24 billion gal./year, including 1.06 billion gal. for fuel and the remainder for chemical feedstocks. Both the Philippines and Thailand plan to produce biomass for ethanol fermentation to produce fuel. In Europe,

ethanol from sugar is gaining proponents, particularly French sugar beet producers who appear to have excess output to redirect toward alcohol production.

Anaerobic Digestion

In anaerobic digestion of biomass, organic materials (manure, grass, seaweed, sludge, or MSR) are decomposed in a two-stage process to produce methane and carbon dioxide. First, moist biomass feedstock is converted by acid-forming (aerobic) bacteria to simple soluble organic compounds, mainly organic acids. Second, these intermediate products are fermented by anaerobic bacteria, and methane, carbon dioxide, and traces of hydrogen sulfide are given off as by-products of digestion. The quantity of these offgases can vary but the mixture generally consists of about 50 percent methane and 50 percent carbon dioxide. This type of decomposition, which occurs naturally in landfills, can be accelerated in suitable structures with controls to optimize the environment of the bacteria.

To establish and maintain a proper balance between the acid-forming and methane-forming bacteria during digestion, temperature, pH, anaerobiosis, nutrients, and toxicity of input must be controlled carefully. Temperature control is the key to successful anaerobic stabilization of organic matter. As temperature increases, biological reactions occur faster, resulting in more efficient operation and lower retention-time requirements, which may vary from 4 to 30 days. Most sewage sludge digestion systems operate in temperatures ranging from 30 to 45 °C. The optimal pH range is 6.8 to 7.2.

The most critical environmental requirement probably is maintenance of anaerobic conditions is the digester. A closed digestion tank that excludes oxygen is essential because methane-forming bacteria are strict anaerobes and even small amounts of oxygen are toxic to them. Because these anaerobes require nitrogen, phosphorous, and other nutrients for optimal growth, it may be necessary to add nutrients to the digester. For example, to maximize anaerobic digestion of solid residue, sewage sludge must be added to the digester to increase the nitrogen content of the mixture. The organic material being processed also must be free of toxic materials that would inhibit digestion.

As the cost of natural gas increases and the supply diminishes, the economic importance of converting manure to methane is increasing. Studies are under way in the United States to assess the technical and economic feasibility of anaerobic digestion of manures to produce medium- to high-Btu gas.[1,5] Several plants are operating to demonstrate the process, including a bioconversion plant in Guymon, Oklahoma, which is the world's first plant to produce gas from cattle manure on a commercial scale. The Guymon plant, which uses about 500 ton/day of manure to produce about 1.6 MMcf of methane/day as well as cattle feed and fertilizer, has been delivering gas to a utility since April 1978. A full-scale methane fermentation facility operating since 1977 at the Monroe State Dairy Farm in Washington produces 7 thousand cubic feet (Mcf)/day of fuel gas. California's first manure-to-methane test facility using an anaerobic digestion process will be designed, built, and operated by Bio-Gas of Colorado, Inc., to convert 1 ton of manure daily to 7 Mcf of synthetic natural gas.[21] Work is also under way to use agricultural and forestry residues as feedstocks to broaden the resource base for anaerobic digestion.[5]

Other U.S. R&D efforts focus on determining the feasibility of producing pipeline quality synthetic natural gas by converting kelp to methane by anaerobic digestion. General Electric will cultivate kelp in the open ocean on an artificial substrate with critical nutrients being supplied by the upwelling of deep water.[1] Kelp production is expected to be about 114 ton/acre-year, with methane production of 875 scf/ton (about 100,000 scf/acre-year). One problem with the kelp scheme is that light does not penetrate seawater adequately to make kelp grow much below 18 m from the surface, while most nutrients are near the bottom. To solve the problem, General Electric will pump nutrient-rich water from the sea bottom.[8] The kelp will be harvested by ship and transported to shore-based conversion facilities.

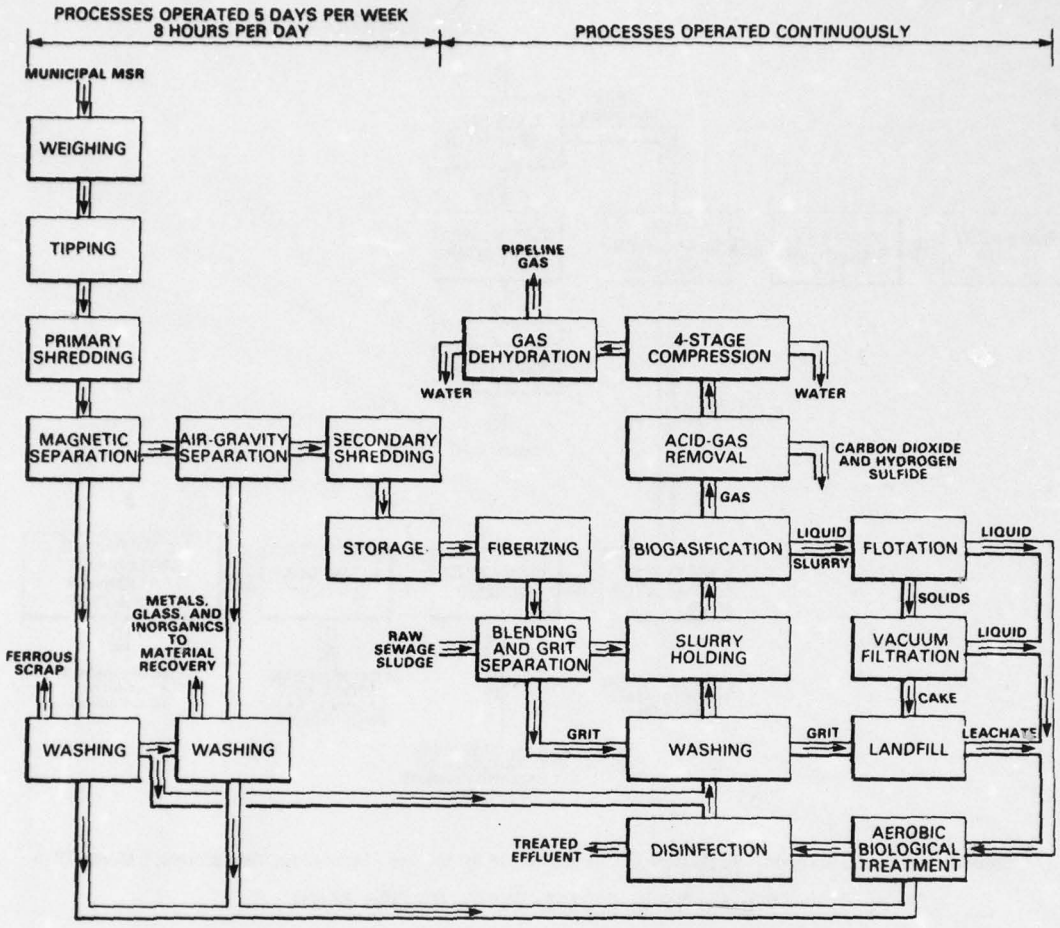
The Institute of Gas Technology (IGT) is producing gas by anaerobic digestion from a number of biomass materials, including urban refuse, kelp, water hyacinths, and a variety of grass.[8] IGT's Biogas process for converting solid residues and raw sewage sludge to pipeline quality gas is shown in Figure 12-3. The process is particularly applicable to organic matter with high moisture content, since anaerobic digestion is most rapid when the solids content in the digester tank is less than 10 percent. Residence time in the digester is 15 to 30 days, which is a limiting factor for process application. In a similar process, Dynatech R/D Company produces gas that is about 50 percent carbon dioxide by volume and requires processing to remove both the carbon dioxide and water vapor. About 3,700 scf of methane are produced for each ton of MSR, which is processed with an additional 0.94 ton of sewage sludge.

In a detailed engineering and economic analysis of anaerobic processes, Southern California Edison Company and other investigators have identified feasible processes for converting MSR to electrical power in an integrated system that includes material recovery, waste heat utilization, and ultimate disposal of all residues and by-products. Processes appearing to be economically feasible involve digesting the entire organic fraction of MSR, then incinerating the residue with steam generation to meet plant power requirements.[1] Other studies focus on assessing economic and technological alternatives for using gas from municipal anaerobic digestion plants and determining and enhancing organic residue-to-methane conversion efficiencies.[18]

Thermochemical Conversion

Conversion to Solid Fuel

Converting MSR to solid refuse-derived fuel (RDF) requires more processing than does incinerating MSR. Figure 12-4 shows a typical process for producing solid fuel from MSR for supplemental firing in a utility boiler. The air classifier separates the light (60 to 80 percent of the MSR) and heavy fractions of the incoming shredded residuals stream. The heavier materials, such as metals, glass, and sand, fall through the airstream and are removed from the bottom of the separator. The light fraction passes through a second shredder to reduce the material to the size required for the fuel—usually 2.5 to 5 cm. The finely shredded fuel, containing 4,000 to 7,000 Btu/lb, is sold for use in grate-fired boilers designed for burning coal and may be burned in a boiler at the processing plant to produce steam for sale. A significant advantage of RDF is its low sulfur content on a Btu basis, about 5 percent of the sulfur of utility grade coal.[16]

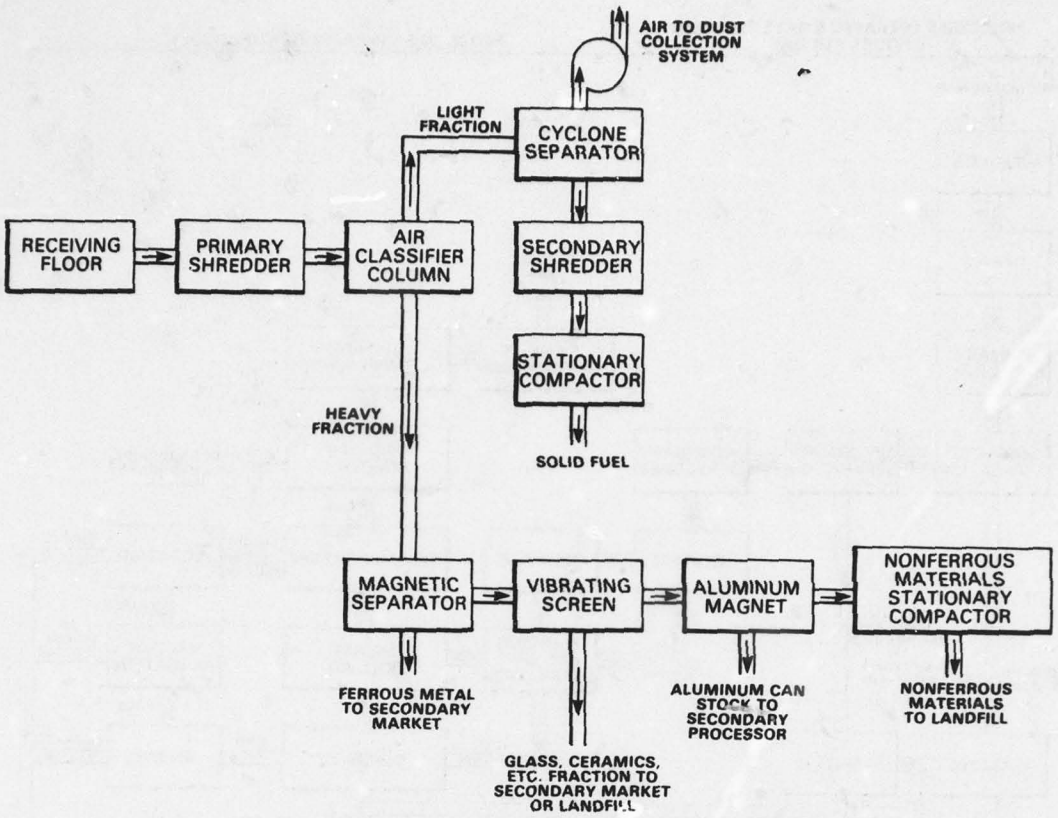


Source: Institute of Gas Technology, *Gas Scope,* Spring 1975.

Figure 12-3. IGT BIOGAS PROCESS

In 1972, Union Electric Company and the city of St. Louis began processing MSR using the Horner and Shifrin process to produce RDF for cofiring with coal at the Meramec power plant. In this process, magnetic and nonmagnetic heavy materials are separated from residues; the RDF produced is fed pneumatically into a boiler and burned in suspension with pulverized coal. A demonstration plant handled 100 to 200 ton/day of residue, providing 10 to 20 percent of the fuel for the Meramec unit (heat equivalent of 50 to 100 tons of coal). The plant, unable to sustain continuous operation for a long period of time, was closed in 1976 because of political and economic problems. However, because of successful development, the process concept now is used in other units, such as the 400 ton/day facility in Ames, Iowa, which has operated successfully since 1976 and produces about 85 percent RDF; the major problem of the Ames unit is the handling of low-density material containing abrasive glass particles.

A facility under construction in Albany, New York, will process about 750 ton/day of



Source: Bechtel Corporation, "Fuels from Municipal Refuse for Utilities: Technology Assessment," March 1975.

Figure 12-4. SOLID FUEL FROM MSR

MSR to produce about 600 tons of RDF and 30 tons of ferrous metals. The city of Milwaukee and the American Can Company have built a 1,600 ton/day facility and plan to begin full-scale operation as soon as plant modifications are completed. Shredding the residue to sufficiently small size and removing noncombustibles from the fuel have been problems.[16] The Southeastern Virginia Resource Recovery Project in Norfolk, Virginia, plans to begin construction of a facility by 1980 for recovering ferrous and aluminum materials for sale and for producing RDF to be burned with coal to generate steam and electricity for sale to the Navy.[18]

Another method for producing RDF is the Combustion Equipment Associates (CEA) hydrolytic chemical treatment of the air-classified organic fraction. In this process (which also is applicable to sewage sludge, crop residues, forest residues, and agricultural crops grown specifically for fuel), a proprietary chemical is added to the shredded fraction in a ball mill to break down the cellulosic structures in the prepared MSR. The end product is a versatile, dry, free-flowing, low-sulfur, powdered fuel called ECO-FUEL® II. This powdered fuel, which has a density of 30 lb/ft^3 and a heating value of 7,500 to 8,000 Btu/lb, can be briquetted for easy handling and may be burned directly or with other fuels. An industrial power plant is burning ECO-FUEL® II to supply electricity, steam, and hot water to Cen-

tury Brass Products in Waterbury, Connecticut, saving 1.25 million gal. of oil per month. The process for making ECO-FUEL® II has been proved by commercial operation in a 900 ton/day plant at East Bridgewater, Massachusetts; a second plant (2,200 ton/day) is being constructed at Bridgeport, Connecticut. Jointly, CEA and Occidental Petroleum Corporation have agreed to construct, own, and operate a $75 million, 1,000 ton/day plant to process the residues of Newark, New Jersey, for 20 years and supply ECO-FUEL® II to Public Service Electric and Gas utility, displacing 700 to 3,500 bbl/day of fuel oil.[4]

Black-Clawson has developed a hydropulping process that produces two grades of RDF (one with a moisture content of 50 percent and another with a moisture content of 5 to 20 percent) and recovers ferrous metals, aluminum, and color-sorted glass cullet. The homogenized form of RDF produced can be easily transported and stored; the low-moisture product can be briquetted for convenience. A demonstration plant in Franklin, Ohio, recovers paper fiber from a wet-pulped mass, but two new installations in Hempstead, New York, and Dade County, Florida, are to burn the wet-pulped residue as the sole fuel in special on-site boilers.

The Maryland Environmental Service (MES) is one of several organizations that are using pelletized RDF on an experimental basis. After air classification of the MSR, the light fraction is fed into rollers and pressed into two-inch pellets. MES has burned a 50-50 pellet-coal mixture in stoker-fired systems at state correctional facilities. Advantages of this pelletized RDF include the ability to use existing combustion systems; ease of storage and transport; and elimination of debris that can be blown about from the light, unpelletized fraction of the residues.

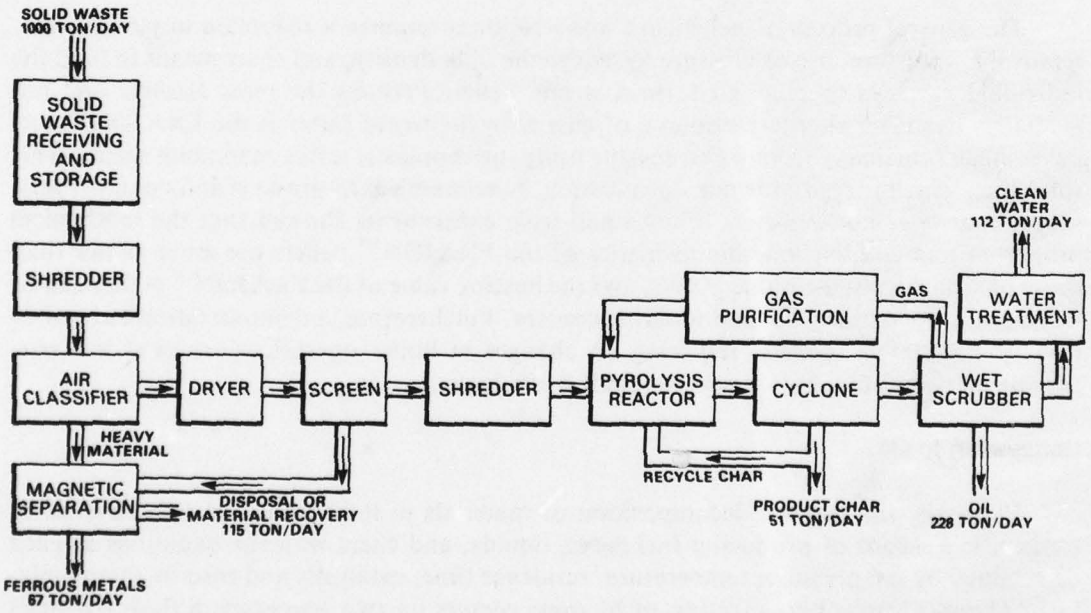
The general process of pelletizing wood residues requires a reduction in particle size, removal of moisture, use of pressure to reduce the bulk density, and some means to bind the individual particles together to form a strong pellet. Perhaps the most feasible and immediately available alternative source of energy in the world today is the FRAJON™ fuel pellet made principally from forest residue using thermoplastic resins as binding agents. This solid fuel, which is ready for mass production, is economical to produce and comes from a source that does not deplete.[1] Initial small-scale experiments showed that the mechanical properties and combustion characteristics of the FRAJON™ pellets are much better than those of straight wood-residue pellets, and the heating value of the FRAJON™ pellets can be increased by increasing the thermoplastic content. Furthermore, a demonstration burn of 25 tons of FRAJON™ pellets, requiring no changes in boiler operations, showed low particulate emissions and high steam generation efficiency.

Conversion to Oil

Pyrolysis, the thermal decomposition of materials in the absence or near absence of oxygen, is a means of producing fuel gases, liquids, and chars with the quantities of each determined by the pressure, temperature, residence time, catalysts, and reactor charge mixture. Thermochemical liquefaction of biomass centers on two processes: a flash pyrolysis process being developed by Occidental Research Corporation (ORC) and a process developed by DOE's Pittsburgh Energy Technology Center in which carbon monoxide is reacted with biomass slurries in an aqueous carbonate solution. Both processes yield heavy fuel oils.[2]

In flash pyrolysis, organics break down into a mixture of vapors (pyrolysis oil, gas, and water) and solid char residue. The reaction, which lasts only a few seconds, takes place at about 510°C and 15 psi and is slightly exothermic. After pyrolysis, the vapors are cooled rapidly by light distillate oil to stop further reaction and to maximize oil production (because further reaction yields more gas).[8] The ORC flash pyrolysis process (see Figure 12-5) converts MSR to fuel oil with recovery of ferrous metals, aluminum, and glass. Other biomass feedstocks, such as agricultural and forestry residues and sewage sludge also can be used. Details of the reactor design and method of operation are proprietary, but the process involves rapid heating of finely shredded organic materials in the absence of air in the heat-exchange system. The incoming feed is heated by contact with recycled char and pyrolyzed to form liquids, gas, and char.

The process operates at near ambient pressure and variable temperatures, and requires no chemicals or catalysts. A variety of feedstocks can be used, and feed pretreatment requirements are minimal. Yields of 1 bbl of oil/ton of raw MSR feed have been confirmed. The oil, which has low sulfur content and about 60 percent of the heating value of No. 6 fuel oil (see Table 12-2), requires special handling because of higher viscosity, corrosive activity on mild steel, and a tendency to degrade at moderate temperature. The ORC process can be modified to produce a finely shredded and dried RDF simply by eliminating the pyrolysis step; about 750 tons of RDF can be produced from each 1,000 tons of MSR processed. In 1977, a 200 ton/day demonstration plant in San Diego, California, began operating, but technical problems have delayed full-scale operation of the complete system. Start-up of a 2,200 ton/day plant is scheduled for late 1979 at Hooker Chemical and Plastics Corporation in Niagara Falls, New York.



Source: J. F. Bernheisel, "Energy From Urban Waste," *Energy Technology V, Challenges to Technology* (Washington, D.C.: Government Institutes, Inc., 1978).

Figure 12-5. ORC FLASH PYROLYSIS PROCESS

Table 12-2. PROPERTIES OF PYROLYTIC FUEL OIL AND NO. 6 FUEL OIL

Property	Pyrolytic Fuel Oil	No. 6 Fuel Oil
Composition (weight percent)		
Carbon	57.0	85.7
Hydrogen	7.7	10.5
Sulfur	0.2	0.7-3.5
Chlorine	0.3	–
Ash	0.5	0.05
Nitrogen	1.1	–
Oxygen	33.2	2.0
Heating value		
Btu/lb	10,600	18,200
Btu/gal.	114,900	148,840
Specific gravity	1.30	0.98
Density (lb/gal.)	10.85	8.18
Pour point (°F)	90[a]	65-85
Flash point (°F)	133[a]	150
Viscosity (at 190°F, SUS)	1,150[a]	340
Pumping temperature (°F)	160[a]	115
Atomization temperature (°F)	240[a]	220

[a]Assumes oil containing 14 percent moisture.

Source: George M. Mallan, "Flash Pyrolysis Turns Refuse into Fuel Oil," *Chemical Engineering,* 19 July 1976.

In other R&D efforts, various biomass materials have been converted successfully to low-sulfur oil by catalytic reaction with carbon monoxide and water at high temperature and pressure. Since 1975, Battelle Pacific Northwest Laboratories has been studying fundamental reaction mechanisms in the liquefaction of cellulosic residues at high temperature and pressure, yield and product quality variations as a function of experimental parameters, and chemical composition of the products. Battelle's research is applicable to commercial biomass liquefaction processes involving aqueous media, such as the residue-to-oil experimental facility in Albany, Oregon.

The Albany facility, designed to test the feasibility of converting forestry and agricultural residues to a renewable supply of synthetic crude oil, is operated by Bechtel Corporation. The synthetic oil has a heating value of about 15,000 Btu/lb, compared to about 19,000 Btu/lb for natural crude oil. In the process, wood or other organic material is dried then ground to fine wood flour. The flour is mixed with an oil carrier to form a slurry and the slurry, pumped to a pressure as great as 4,000 psi, is mixed with a catalyst (sodium hydroxide) and hydrogen and carbon monoxide gases. The material is heated in a reactor at 260 to 370°C to convert the wood slurry to oil.[22] Bechtel is working on methods for separating residues from the oil and on improving product quality in general.[8]

Another process for producing oil from biomass feedstock has been demonstrated by Tech-Air Corporation using a large-scale, 50 dry ton/day prototype facility. Tech-Air demonstrated process economics, feasibility, and reliability for effectively converting the high heat values of wood, agricultural, industrial, and classified municipal residues into more useful energy forms. The low-pressure, vertical-bed pyrolysis system is pollution free and produces gas and oil as clean-burning fuels while producing a char suitable for subsequent gasification and combustion, charcoal briquetting, and activated carbon production.[18]

Conversion to Gas

Production of clean fuel gas from residue by gasification—pyrolysis—is one of the most promising possibilities for coping with the low heating value of solid residue and with the tar and smoke produced during combustion of solid residue.[1] Pyrolysis of MSR to a fuel gas is illustrated in Figure 12-5. The composition of the product gas is shown in Table 12-3. The gas has a heating value of about 300 Btu/scf with properties very similar to medium-Btu, coal-derived gas.

Table 12-3. COMPOSITION OF PYROLYSIS FUEL GAS

Component	Volume (Percent)	Weight (Percent)
Carbon monoxide	44.2	58.9
Hydrogen	31.0	2.9
Carbon dioxide	13.2	27.6
Methane	3.8	2.9
Ethylene	0.9	1.4
Nitrogen	0.9	1.2
Water	6.0	5.1

Source: Bechtel Corporation, "Fuels From Municipal Waste for Utilities: Technology Assessment," March 1975.

A summary of processes for gasifying solid residue is provided in Table 12-4. Technology transfer from entrained-bed coal gasification and oxygen-blown residue gasification processes presents near-term potential for adapting biomass as feedstock by 1985. Advanced catalytic hydrogasification being developed for biomass can become economically feasible during the 1990s.[1]

Biomass materials, whatever their origin, are very similar chemically and in gasification reactivity, and also share many physical characteristics that make their handling in gasifiers difficult. These materials usually have a low bulk density, are fibrous, and therefore tend to shred in fibrous strands rather than into particles. Modification of existing medium-Btu gasification technology to use biomass probably would result in processes with rather low energy efficiencies. New gasification processes using the special fuel characteristics of biomass may give higher total energy efficiency.[1]

Advanced thermochemical gasification processes specifically developed for biomass feeds are in various stages of bench-scale and pilot-plant development. Factors considered in selecting appropriate processes for biomass gasification are composition and pressure of the raw gas produced, process performance, ability to handle biomass feedstock, simple operation and maintenance, and competitive production cost. The gas produced should contain no undesirable by-products and few undesirable components such as particulates, sulfur, and inerts. Gasification capacity and gas production rate should be high as well as carbon conversion and thermal efficiencies. The process equipment should be able to accept moist biomass feeds, gasify large chunks of biomass, operate with nonuniformly sized feed, and handle a variety of biomass, including wood, crop residues, and mill residues. Presently, no ideal biomass gasification process exists that meets all of these criteria. A gasification process with a potential of making recovery of energy from biomass practical is being developed by Garrett Energy Research and Engineering Company, Inc.; the process, using a modified two-stage drying, multiple hearth furnace, is designed to overcome problems such as the high moisture content of biomass, the difficulty of feeding biomass through process equipment, and the low tonnage availability of biomass at any one location.[1]

Because of the low energy content of biomass relative to coal and because of the low bulk density of biomass, the reactor size required for gasifying biomass to yield a given amount of product is larger than is required for gasifying coal. A wide range of reactor designs and conversion chemistries are being studied, especially for producing low-Btu gas having heating values of 100 to 450 Btu/scf. The processes that yield gases with heating values near the high end of this range generally can be categorized as systems that use pure oxygen in partial oxidation systems, two-bed systems that keep the nitrogen in air separated from the product gas, pure pyrolysis systems, or hydrogasification systems.[1]

In steam gasification processes under development, biomass is pyrolyzed at relatively

Table 12-4. SUMMARY OF EXISTING SOLID RESIDUE GASIFICATION PROCESSES

Pyrolysis Reactor Type	Description	Product Distribution			Development Status	
		Solid (Btu/lb)	Liquid (Btu/lb)	Gas (Btu/ft³)	Pilot	Commercial
Vertical Shaft						
Occidental Research Corporation—Flash Pyrolysis Process	This flash pyrolysis process uses an adiabatic fluid bed reactor operating at about 500°C on presorted refuse (dry, fine shredded, combustible, relatively free of glass) to produce fuel oil, char, and gas. Gas is used for process heat.	9,700	10,500	550	4	200
Carborundum Company—Torrax Process	Mixed municipal refuse is gasified at 1,650°C with air heated to 870°C in ceramic heat exchanger fired with supplementary fuel.	–	–	150	75	–
Union Carbide Corporation—Purox System	Gasification of mixed municipal refuse in a shaft furnace at 1,650°C with oxygen produces medium-Btu gas and slag. The 200 ton/day plant in Charleston, West Virginia, produces about 7 million Btu of gas/ton of refuse, about four times as much energy as it uses.	–	–	300	5	200
Urban Research and Development Corporation	Mixed municipal refuse is gasified at a reactor temperature of 1,425°C with air heated to 480°C in metal heat exchanger fired with gas generated on site.	–	–	150	120	–
Horizontal Shaft						
Barber-Colman Company	Fine shredded material (to 5 cm) is gasified in a closed horizontal shaft reactor (650°C) with a circulating molten lead bed as the heat transfer media.	–	–	–	–	–
Rotary Kiln						
Monsanto Enviro-Chem Systems, Inc.—Landgard System	Presorted and shredded refuse (to 10 cm) is processed in a continuous rotary kiln 815°C with internal heating by countercurrent flow of deficient air plus supplementary fuel. The 1,000 ton/day plant in Baltimore, Maryland, was shut down in 1978. Problems included corrosion, gases that continued burning after leaving the combustion zone, excessive off-gas temperatures, slagging caused by excessive residue discharge temperatures, and stack gas emissions well above EPA standards.	2,500	–	130	35	1,000
Fluid Bed						
West Virginia University	Dry, finely pulverized, noncombustible, free refuse is gasified in a fluid bed reactor (760°C) with heat addition. The process uses 30 ton/day make-up sand.	–	–	450	500	–

Source: *Energy From Biomass and Wastes,* Symposium papers presented 14-18 August 1978, Washington, D.C. (Chicago, IL: Institute of Gas Technology, 1978).

low temperatures (300 to 500°C) to produce volatile matter and char; at somewhat higher temperatures (600°C), the volatile matter reacts with steam to produce a hydrocarbon-rich synthesis gas. Because steam is a necessary reactant in the process, the high moisture content of most biomass fuels can be viewed as an attribute. The presence of steam in the reactor vessel serves to minimize the production of valueless oils, tars, and condensables, which normally result from pyrolysis reactions. Relatively mild conditions are sufficient to reduce the production of condensables below 10 percent of the initial feedstock weight. The hydrocarbon-rich synthesis gas, which is produced without catalysts from the steam gasification process, can be burned directly as a high-quality fuel, or used for the production of methanol, gasoline, Fischer-Tropsch liquids, ammonia, methane, or hydrogen by commercially available technologies. The carbon residue is a high-quality, low-sulfur solid fuel, however, economics may favor its use as an activated carbon.[1] The objective of a study conducted by researchers at Princeton University is to determine optimal conditions for producing synthesis gas from organic matter by steam gasification.[18]

Catalytic gasification efforts have been limited to the use of sodium carbonate in work by Pittsburgh Energy Technology Center and Battelle Pacific Northwest Laboratories. In search for catalytic systems more appropriate for wood, Battelle found that recycled wood ash itself is an effective gasification catalyst. The wood ash is effective when applied by simply spraying a water solution of it on the wood, and therefore could easily be applied as wood chips move along a conveyor belt. Use of wood ash as a gasification catalyst for wood seems to have considerable potential, increasing gasification rates and promoting the water-gas shift reaction in addition to being one of the by-products of a wood gasification plant. Economic feasibility studies based upon use of a proprietary Battelle gasification system that utilizes an entrained phase heat carrier indicated that an intermediate-Btu gas can be produced in 1,000 ton/day plants and sold at a price competitive with other clean fuels such as liquefied natural gas and No. 2 heating oil.[1]

In a pilot project at Texas Tech University, use of a countercurrent pyrolysis reactor that allows volatile organic compounds to escape from the heating zone very rapidly results in a different product mix than has been observed in other pyrolysis research. The product contains ammonia, synthesis gas, and/or low-Btu gas as well as unusually high concentrations of ethylene. Feedstocks for the thermochemical process include manure, wood, and field residues. The influence of temperature, residence time, pressure, and feedstock materials on the yield and quality of the products is being determined in a 0.5 ton/day test reactor.[18]

To follow up on the NASA research on water hyacinths, United Gas Pipe Line Company plans to design, construct, and operate a pilot plant to produce about 1 MMcf/day of gas from about 100 tons of organic material. United Gas will use hyacinths to clean sewage water, then will make gas from the hyacinths, Bermuda grass, and sewage in its pilot plant. The project will use residue from New Orleans.[6]

Energy Resources Company, Inc., has developed a residue and biomass energy utilization model based on using a fluidized-bed pyrolysis system to transform agricultural and community residuals to oil, gas, and char, which can be used to meet much of the 7.7 percent energy requirement for growing and processing crops in an agricultural community.

The process not only operates with high thermal efficiency to produce usable products (oil, gas, and char), but also has multiple feedstock capabilities and provides air emissions control. The fluidized-bed reactor, with a bed diameter of 0.5 m and fluidized height of 1.1 m, can handle about 0.5 ton/hour of feed. Experimental pyrolysis of corncobs showed that gas yield increased steadily with temperature up to 900°C and leveled out at 60 percent; oil yields decreased rapidly down to about 7 percent, and char data were highly variable.[1]

Experimental data on various biomass gasification processes are shown in Table 12-5. Estimates indicate that with 6 ton/day of biomass (50 percent moisture) the daily output from a pilot-scale Wright-Malta gasifier will be 67,000 scf of fuel gas with a heating value of 750 Btu/scf (after carbon dioxide scrubbing). The simplicity of the Wright-Malta process, which uses a combination of catalytic pyrolysis and hydrogasification, may lead to commercial production of medium-Btu gas at about $2.50/million Btu. Battelle estimates that its biomass gasification process, which uses a multi-solid fluidized-bed reactor system capable of operating at very high velocities, can produce a medium-Btu gas (300 Btu/scf) at about $2.90/million Btu from a 500 ton/day gasification plant using wood chips available at $1.00/million Btu.[1]

ENVIRONMENTAL ISSUES

Many bioconversion techniques are beneficial to the environment. The resource recovery and reduced demand of landfill sites favor MSR energy recovery systems for urban areas. Additionally, the fuels derived from MSR generally are low in sulfur, making them attractive to the utility industry. Of concern, however, are land and water resource requirements for terrestrial biomass production; air and water quality effects from silvicultural and agricultural operations; depletion of soil organic content because of residue removal; impacts from combustion of biomass; production of gaseous, liquid, and solid residues from thermochemical biomass conversion; and disposal of sludge from anaerobic digestion (see Table 12-6). Competition of terrestrial biomass production with other uses of a resource, ecological and climatological effects of ocean kelp farms, transportation of biomass and derived fuels, machinery noise from harvesting equipment, and health of energy plantation workers are among other issues related to bioconversion techniques.[23]

The substantial land and water requirements of terrestrial biomass plantations are critical factors that determine biomass production sites as well as affect the surrounding environment. Land availability could be a problem because individual biomass production tracts, which require 21,000 to 60,000 acres compared with the average farm of 100 to 600 acres, could displace smaller farms to form large biomass farm tracts. Water requirements vary depending on plant species and soil type, but the high-yield crops being considered for terrestrial biomass production generally require large amounts of water for adequate growth. Thus, the scarcity of water supplies in arid regions precludes establishment of biomass farms unless supplies can be channeled from water-abundant areas. A potential long-term impact of land and water use for biomass production is that development of competing uses of land and water (for example, food and fiber production) could be restricted in some regions, resulting in adverse socioeconomic impacts.

Table 12-5. EXPERIMENTAL DATA ON BIOMASS GASIFICATION

Process	Reactor Type	Status	Feedstock	Combustion Zone (°C)	Production Gas Composition (Percent)							Net Heating Value (Btu/scf)
					CO	H_2	CO_2	CH_4	C^{+2}	N_2	H_2S	
Bailie	Fluidized bed	Originally developed for solid residue	Dry bagasse	980	23.3	35.4	23.0	8.5	9.8	—	—	401[b]
Battelle-Northwest	Fixed bed	Pilot plant reactor developed for biomass	Wood residue	a	24.1	20.6	13.4	2.1	0.3	38.9	—	179[c]
Battelle-Northwest	Fluidized bed	Bench-scale reactor developed for biomass	Wood residue + catalyst	650	40.5	21.2	24.6	11.4	2.0	—	—	262
Koppers-Totzek	Entrained bed	Commercial process originally developed for coal	Wood	1,900	41.0	17.0	33.4	0.2	—	0.1	—	—
Moore-Canada	Fixed bed	Full scale in operation late 1975	Wood residue	1,200	22.8	18.3	9.2	2.5	0.9	45.8	—	132
Pullman-Kellogg	Molten salt	Commercial process originally developed for coal	Bagasse (37 percent moisture)	a	24.9	34.0	33.9	7.1	0.0	0.1	0.0	181
Purox	Fixed bed	Commercially proven process, originally developed for municipal solid residue	Bagasse (6 percent moisture)	1,650	47.9	30.1	11.8	5.2	4.8	0.2	0.02	357
Wellman-Galusha	Fixed bed	Commercial process originally developed for coal	Wood	1,370	44.4	30.2	20.0	4.0	—	1.5	—	279

[a]Not available.

[b]Dry.

[c]Gross heating value.

Source: *Energy From Biomass and Wastes,* Symposium papers presented 14-18 August 1978, Washington, D.C. (Chicago, IL: Institute of Gas Technology, 1978).

Table 12-6. BIOCONVERSION ENVIRONMENTAL ISSUES BY IMPACT AREA

Issue	Impact Area							
	Air Quality	Water Quality	Land Use/ Solid Waste	Ecology	Health and Safety	Esthetics	Social/ Institutional	Resources
Land and water resource requirements for terrestrial biomass production		X	X			X	X	X
Air and water quality effects from silvicultural and agricultural operations	X	X		X				
Depletion of soil organic content due to residue removal				X				X
Impacts from combustion of biomass	X	X	X	X				
Gaseous, liquid, and solid residues from thermochemical biomass conversion	X	X	X		X			
Disposal of sludge from anaerobic digestion		X	X					
Competition of terrestrial biomass production with other uses of resource			X				X	X
Ecological and climatological effects of ocean kelp farms		X		X				
Transportation of biomass and derived fuels	X							
Machinery noise from harvesting equipment						X		
Health of energy plantation workers					X			

Source: U.S. Department of Energy, "Environmental Development Plan (EDP), Fuels From Biomass, 1977," DOE/EDP-0005, March 1978.

Biomass plantations have the potential to affect air and water quality significantly, primarily through dust emissions and sediment loads to waterways. Air quality is affected by such biomass production activities as soil cultivation, logging, harvesting, and heavy equipment traffic over unpaved areas. The major water quality impact of intensive crop or forest cultivation is sedimentation in surface water caused by rain erosion and/or irrigation runoff from exposed soils. Pollutants resulting from silvicultural or agricultural runoff include nutrients, pesticides, organic loads, and fire retardants. About 50 percent of the total sediment yield in inland waterways is the result of cropland soil erosion; the principal sources of soil sediment loads in forestry management areas are skid lanes and logging and fire roads. Advanced cultivation methods, such as "no-till" farming and contour-type plowing schemes, aid in reducing runoff. Also, when coppicing species are used, dust and sediment discharge are reduced because tilling would only be done every fourth and sixth rotation (every 2 to 6 years).

Removing silvicultural and agricultural residues and total harvesting or clear-cutting reduce the amount of organic matter that decaying residues provide to the soil and may limit

future crop or forest growth. Impacts of residue removal can be reduced by removing only part of the residues or by no-till farming, which leaves the soil undisturbed for several seasons and preserves root structure, providing aeration and organic content to the soil. The extent to which residue removal can be practiced safely has not been determined for most of the species considered for use in a biomass plantation scheme. For example, forest residue removal may have beneficial impacts: eliminating the clogging of streams by forest residues decreases the occurrence and intensity of forest fires and thereby contributes to better forest management.

Direct combustion of biomass may, in some cases, emit more air pollutants (nitrogen dioxide, carbon monoxide, and particulates) than does combustion of fossil fuels. These emissions can be reduced by manipulating variables such as wood selection, type of particulate controls, furnace design, and fuel input rate to achieve optimal conditions. Water pollutants, which originate from fuel storage and ash deposits, can be reduced or eliminated by proper land filling and other disposal options, such as recycling ash to plantation sites to serve as fertilizer. With proper management, the relative impacts from burning biomass should be significantly less than those encountered in coal combustion.

Potential air and water pollutants from the various thermochemical bioconversion processes include trace toxic sulfur compounds such as hydrogen sulfide and low-molecular weight oils and gas condensates such as phenols. Hydrogen sulfide emissions can be eliminated by preventing leaks or chemically treating product gases. Water quality can be affected by the low-molecular weight oils, phenols, leachates from char and ash residues, and scrubber solution runoff that may enter water bodies by direct discharge and by percolation to subsurface waters from evaporation ponds. Possible impacts may be aggravated when water is used as a reactant, as proposed in some thermochemical schemes. Adverse water quality effects can be lessened by the use of oil flotation devices, activated sludge treatment, lagooning, or evaporation/infiltration ponds. The tars and oils produced by thermochemical conversion superficially resemble coal tar and, therefore, may present health and safety concerns.

Overall, potential impacts related to biomass thermochemical conversion would be significantly less than those found in similar coal conversion schemes, because of the primary carbohydrate nature of biomass, which results in cleaner products. Nevertheless, because of the severe operating conditions of the thermochemical processes, the production of some undesirable environmental residuals is difficult to avoid.

Converting biomass to fuel by anaerobic digestion produces a sludge that must be disposed of or recycled carefully to avoid pollution of groundwater or surface waterways. Sludge is disposed of in an evaporation lagoon; discharge from the pond, if it occurs, must be channeled into waterways with a sufficient flow rate to dilute pollutants. Sludge from large digesters may be used as fertilizer and soil conditioner, but should not be applied to one area for an extended period because salts and heavy metals could build up in the soil.

ECONOMICS

The economics of technically feasible, demonstrated biomass or residue energy resources and processes ultimately will determine when and how a particular process is commercialized. Available fossil fuels are still sufficiently low in cost to make the economics of producing substitute fuels from residues borderline or unattractive if the process is viewed specifically as an energy-producing system. The increasing cost of residue disposal by conventional methods and the related environmental factors, together with the credits for the energy products, tend to make combination disposal-energy recovery processes more competitive with both conventional residue disposal and energy costs. In western Europe, where fuel costs are high and landfill sites are scarce, 243 municipal residue-to-energy combustion plants are operating. When the same kinds of conditions begin to prevail in the United States, the rate of commercializing residue-to-energy projects will increase considerably.[1]

The same economic conditions currently exist for manure gasification processes; methane revenues alone do not justify the process and in fact provide a lower return than the by-product animal feeds. In cases where a large renewable energy resource is generated on-site and there is a need for fuel, such as in a lumber mill or a sugarcane processing plant, the economics are often favorable for direct processing, such as bagasse or wood combustion, to steam and electric power.[1]

Many economic analyses recently have been performed on biomass and residue conversion processes, biomass production, and integrated synthetic fuel systems supplied with biomass raw materials. Studies have shown that synfuels from biomass are more expensive than conventional fuels and that some biomass conversion systems that do not appear to be economically feasible have already been or are about to be commercialized (synthetic natural gas from manure, electric power from wood, alcohol from sugarcane). These observations suggest that a very careful study of the information resulting from such comparative economic analyses is essential and that continual improvements and revisions must be incorporated in the assumptions and methods used to make the results reflect what is actually economically feasible and what is happening in the commercial world.[1]

Landfill gas recovery and purification is a proved, economically feasible means of energy recovery from solid residue, provided the necessary combination of technical expertise and financial backing is available. Increasingly, landfill gas recovery is expected to contribute significantly to the nation's energy supply in the future, even though it remains a high-risk, capital-intensive business because of the inconsistencies in landfill design, composition, and operation. Cost estimates for collection, treatment, and yearly expenses of methane recovered from landfills indicate that landfill gas, while not presently competitive with natural gas or oil, is competitive with liquefied natural gas and synthetic natural gas. Estimates for an EPA-funded gas recovery demonstration project in Mountain View, California, indicate an energy output of 1.1 scf of methane per pound of solid residue and energy costs of $2.79/million Btu.[1]

In a study of multiple use materials from forests, Georgia Institute of Technology indicated that raw wood biomass costs $7 to $10 per ton to collect and transport to a utilization site. Pretreating the wood by pelletizing and drying increases its value to about $22/ton and

makes its properties more uniform. However, it is not yet clear that the added cost of pelletizing is justified if the wood is to be used for direct conversion to energy. The cost of the pelletized biomass is equivalent to about $1.33/million Btu compared with a projected biomass-derived energy price of $2/million Btu in 2000. Projected energy costs of gasoline are $4.20/million Btu; natural gas, $3.90/million Btu; and coal, $1.60/million Btu.[2] In other studies, user costs for fabricated fuel pellets made from a variety of cellulosic residues are reported to be about the same as costs for 12,500 Btu/lb coal on an equivalent Btu basis. Such pellets have heating values of 8,000 to 9,000 Btu/lb.[1]

In general, the less processing the residue undergoes, the greater the net energy recovered for useful application as a fuel and the less process energy required. Thus, pyrolysis, which creates a more refined intermediate fuel product, is less energy efficient than RDF, which makes no chemical change in the residue material. However, the gas, liquid, or steam product would be expected to sell for a higher price and therefore may be justified economically.[7]

Estimated gas production costs for three promising biomass gasification systems (Koppers-Totzek entrained-bed coal gasification, Purox oxygen-fed fixed-bed residue gasification, and Wright-Malta catalytic biomass hydrogasification) are shown in Table 12-7. In the Koppers-Totzek system, treatment and ash removal may not be required for biomass gasification. However, because both Koppers-Totzek and Purox require an oxygen plant, the high capital and operating costs are largely attributed to the costly oxygen-fed gasification system. The low cost of the Wright-Malta system is reflected basically by its simple design and operation, however the system cost easily can be escalated to 50 percent higher if its heat transfer problem develops in a large-scale application of the system. The catalytic hydrogasification process developed for biomass can produce medium-Btu gas (500 Btu/scf) at about $3/million Btu for a 1,700 ton/day biomass plant. Catalytic hydrogasification eventually will produce medium-Btu fuel gas at about $2/million Btu.[1]

Table 12-7. ESTIMATED GAS PRODUCTION COST, BY FEEDSTOCK COST AND PROCESS[a]

Feedstock Cost ($/Million Btu)	Production Cost ($/Million Btu)		
	Wright-Malta Catalytic Hydrogasification Process	Purox Pyrolytic Process	Koppers-Totzek Gasification Process
1.0	1.83	4.69	4.87
1.5	2.35	5.36	5.44
2.0	2.87	6.03	6.01
2.5	3.39	6.70	6.58

[a]Based on feedstock containing 50 percent moisture and 4,250 Btu/lb heating value.

Source: *Energy From Biomass and Wastes,* Symposium papers presented 14-18 August 1978, Washington, D.C. (Chicago, IL: Institute of Gas Technology, 1978).

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13. OCEAN ENERGY

The amount of energy potentially available in the sea—both visible and invisible—is practically limitless. Estimates of this energy are staggering: 25 billion kW of energy are constantly being dissipated along the world's shorelines by waves; tides could be harnessed to produce 1,240 billion kWh/year; the Gulf Stream off Florida has a volume flow of over 50 times the total discharge of all the rivers of the world; enough electricity could be generated from heat engines operated on the temperature differential between surface and deeper ocean waters to provide more than 10,000 times the world's yearly electric power requirements.[1]

Since the supply of energy in the ocean is vast, renewable, and free, extraction of energy from the ocean is an attractive concept. However, the energy density of water in the oceans is low compared to that of water in conventional energy-producing applications, and the cost of extracting this free energy in a usable form is high. For example, the maximum head of water that can be expected in a tidal power plant is 10 m, which is considered marginal for hydroelectric power.[2] Similarly, the temperature differences in the ocean are many times less than those in a fossil fuel plant between the boiler and the condenser, and the amount of energy that can be extracted from a unit mass of working fluid is proportionately less. A representative kilogram of water at the surface of the Gulf Stream, moving at a speed of 2 m/s and having a temperature of 25 °C, which is 20 °C above that at 1,000 m depth, possesses about 2 joules (J) of kinetic energy and about 83,800 J of thermal energy; about 5,600 J of this thermal energy is recoverable.

Approaches to extracting ocean energy include:

- Tidal energy systems, which utilize the potential energy of a head of water in a way similar to the production of hydroelectric power.
- Wave energy and ocean current energy systems, which utilize the kinetic energy of water movement.
- Ocean thermal energy systems, which use the thermal difference between warm surface waters and cool subsurface waters.
- Salinity gradient energy systems, which use the chemical difference between two sources such as river water and seawater at a river mouth.

TIDAL ENERGY

Tidal energy is one of the oldest forms of energy used by man. A tidal mill, built in the Deben Estuary in Great Britain, was mentioned in records as early as 1170, and is still in operation. Engineering ingenuity has resulted in a large number of schemes that make tidal power a reliable source of energy. The energy is available, at will, as peak power or as steady

power regardless of the time for ebb and flow. It is predictable, as far ahead as needed, from the movements of the celestial bodies that govern the tides.

Tidal energy recovery requires large capital investments, but once built, tidal power installations may last much longer (with small maintenance costs) than thermal or nuclear power plants, which must be replaced every 30 years. Tidal power generating facilities are operating at La Rance (in France) and Kislaya Guba on the White Sea (in the USSR). The average tidal range at La Rance is 8.5 m and at Kislaya Guba, 4 m. Active investigations of the use of tidal power as an alternative source of energy are being undertaken in France at the Bay of Mont St. Michel, Canada at the Bay of Fundy, England in the Bristol Channel, Korea, and the USSR. In the United States, the Passamaquoddy project in Maine was recently reappraised and the potential of tidal power in Alaska considered.

Resource

Tides are caused by the attraction of the earth by the moon and the sun. The attraction of the moon is 2.2 times more significant than that of the sun. The moon's gravity acts on the entire earth mass, but pulls the nearest part away from its center. The furthest part is also pulled away because it is subjected to smaller gravitational force than its center. Thus, a high tide is produced beneath the moon and at the "anti-moon." High tides occur on opposite sides of the earth, and, because the earth rotates, each side experiences two high tides and two low tides every day.

This simplified picture is complicated by several phenomena:

- When the sun, moon, and earth are lined up, spring tides occur, and when they are at right angles, neap tides are produced.
- The orbit of the moon and the sun with respect to the earth are elliptical with varied inclinations with respect to the earth. The tidal amplitude is largest when the moon or sun is closest to the earth.
- The earth is not covered uniformly by water, and each basin has its own varying dynamic response.
- The solid earth itself undergoes tidal distortion, typically 0.5 m. What is observed to be ocean tide is actually ocean tide minus earth tide. Earth tides also interact with ocean tides in a complex manner.

The wide deep ocean basins respond directly to the external gravitational disturbances created by the moon and sun. The shallow seas and bays surrounding the continents are subjected to and respond to the tidal motion prevailing in the deep ocean. The responses of the shallow tidal basins are a function of size and depth. Large tidal ranges are generally the result of a matching of periods between deepwater tidal excitation and the free natural oscillation of large embayments. Much progress is now being made in predicting shallow water amplitude by analyzing deepwater tides and shallow water response to deepwater excitation. The tidal basin boundaries are not fully reflective, like vertical walls, but contain a dissipative feature. Turbulent energy dissipation is a nondeterministic phenomenon. Despite all these complexities, tidal amplitudes and time predictions along the coastline can be made with great accuracy. The error rarely exceeds 50 cm in tidal range or one-half hour in phase.

The total tidal energy dissipated by friction in the shallow coastal waters of the world has been estimated to be 1.1 million MW, which theoretically could be converted into electrical power.[3] Of this amount, 0.022 percent is now being converted to electricity. If the optimum sites in the United States, Canada, and Europe can be developed, as much as 4.4 percent could be converted to electricity. These optimum sites can be identified from energy-density considerations; that is, the amount of energy that can be extracted from a tidal pool is proportional to the volume of water available as head, which is given by the tidal range (differences in height between high and low tide). Therefore, ideal sites have large tidal ranges and large areas capable of being dammed.

At the La Rance tidal power installation, the only existing commercial plant, the tidal range is between 5 m at low neaps and 13.5 m at equinoctial spring tides; the useful impounded volume is 184 million m^3 contained by a dam 750 m long. Tidal ranges at this and other sites are given in Table 13-1.

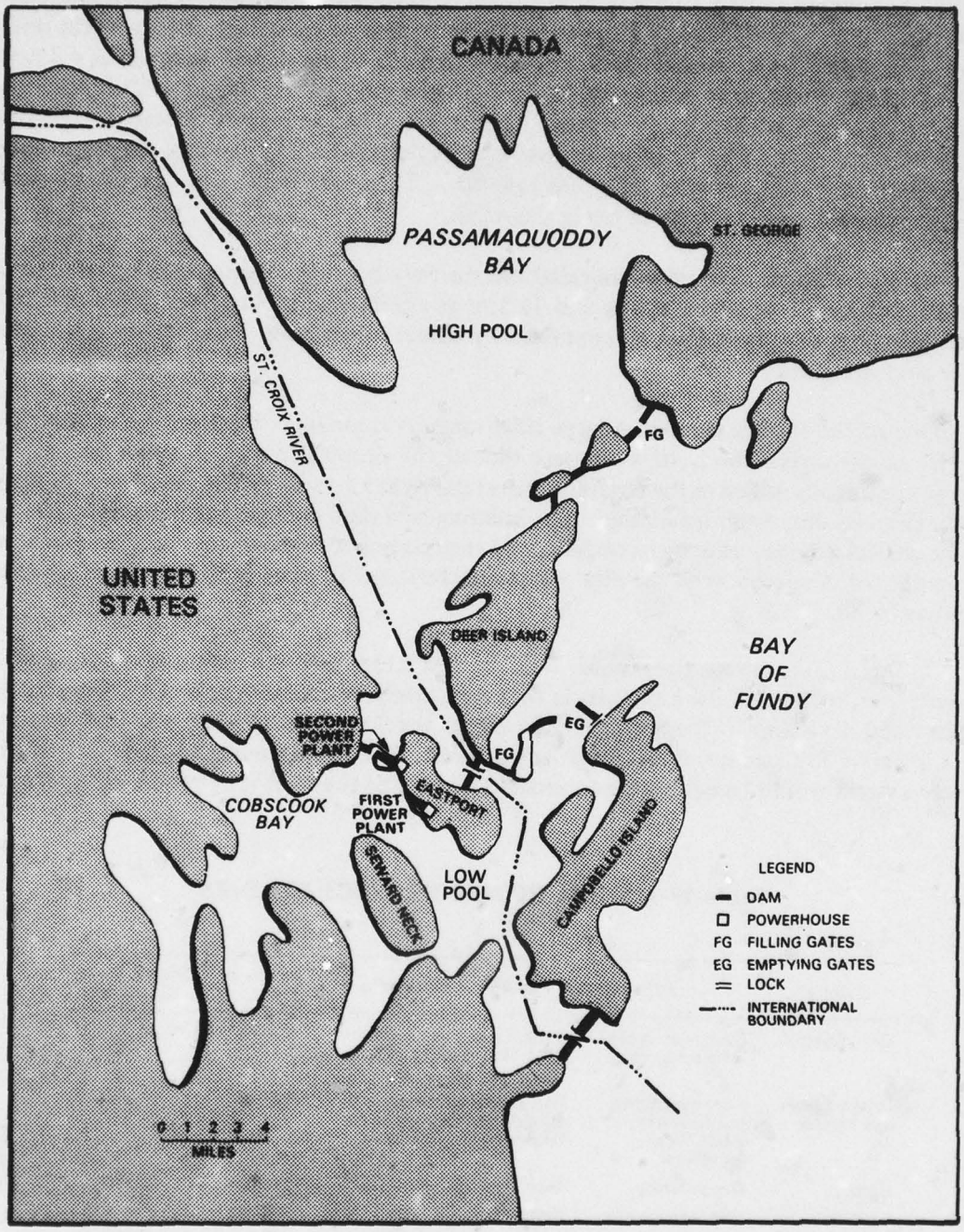
One of the factors creating a large tidal range is resonances between the natural frequency of the coastal body of water and that of the deepwater tide. A small amount of energy continually added to the coastal water at the right intervals results in an amplification of the original deepwater tidal range. The building of a dam changes the natural frequency of the coastal water by altering its outline, with the result that the resonance may be enhanced or dampened. Consequently, the tidal range may be larger or smaller than it was before the dam was built.

In Britain, the Severn Estuary has been studied intensively as a potential site for a tidal power plant, because of the high tides in that area, which result from resonance between the estuary and the ocean.[4-7] The average tidal range in the Severn Estuary is 8.8 m, and the tidal pool is about 30 times larger than that at La Rance. The total generating capability of the Severn system would be equivalent to about 2 percent of the electricity produced in Britain

Table 13-1. TIDAL POWER PROJECT STUDIES

Country	Location	Physical Characteristics	Tidal Range (m)	Electric Power (GWh/year)
United States	Cook Inlet, Alaska (near Anchorage)	360 km long, varying from 21 to 96 km wide; five possible sites	4.6-7.3	86,000
United States and Canada	Passamaquoddy, Bay of Fundy, Maine/New Brunswick	Double basin: Passamaquoddy Bay (260 km^2) and Cobscook Bay (105 km^2)	3.6-8.2	1,900
Canada	Bay of Fundy	Over 250 km^2	7.0-16.5	50,000
Argentina	Valdes Peninsula	Single basin with canal	—	75,000
Great Britain	Severn Estuary	Single or double basin	13.7	10,500
France	La Rance Bay of Mont St. Michel	Single basin (21 km^2) 500 km^2	5.0-13.5 3.6-12.5	600 25,000

Sources: T. J. Gray and O. K. Gashus, eds., *Tidal Power* (New York: Plenum Press, 1972), and U.S. Department of the Interior, "The International Passamaquoddy Tidal Power Project and Upper Saint John River," July 1963.

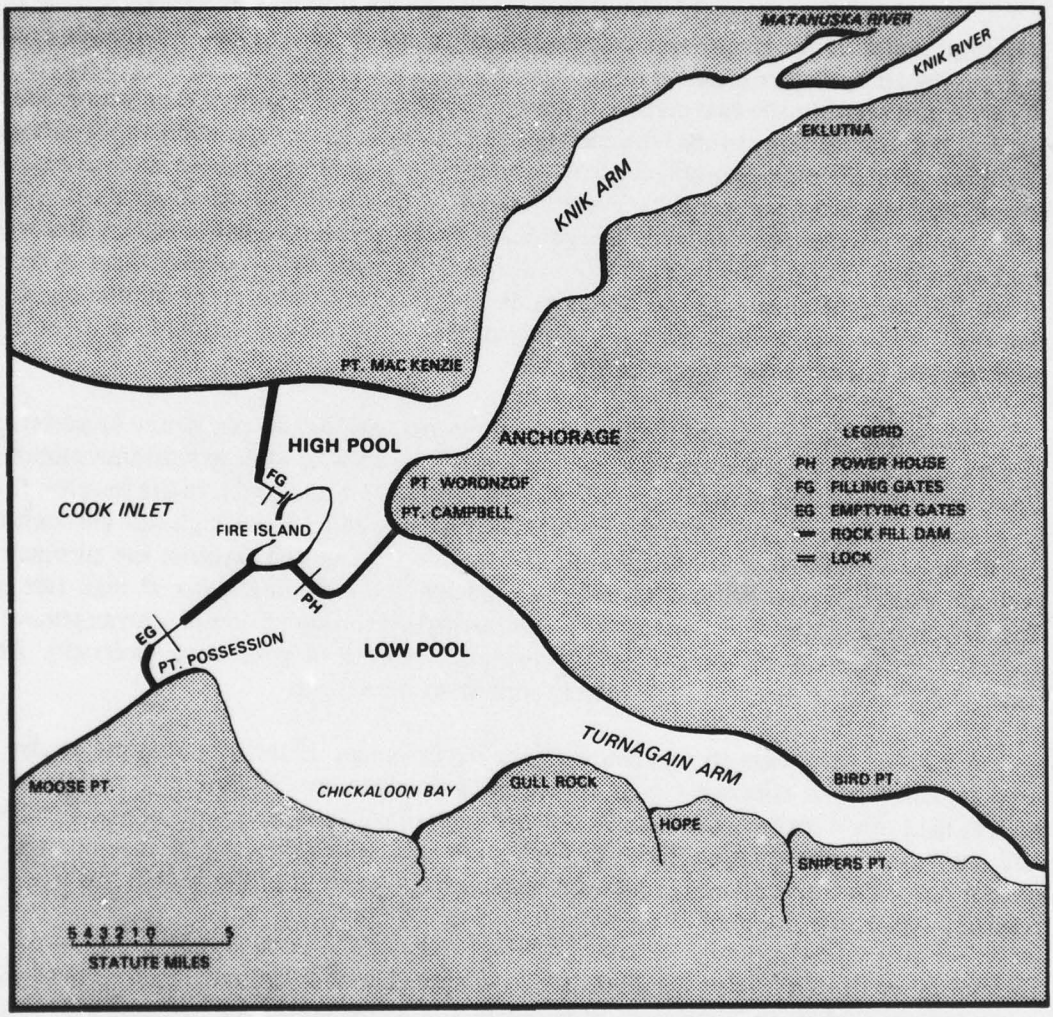


Source: U.S. Energy Research and Development Administration, Division of Geothermal Energy, "Tidal Power Study," EX-76-C-01-2293, March 1977.

Figure 13-1. PASSAMAQUODDY TIDAL POWER PROJECT

at present. In a two-pool configuration, the system could also be used for large-scale pumped storage (see Chapter 8), making it a more useful addition to the electrical network.

In the United States, two locations with potential for generating electrical power from tides have been studied: Passamaquoddy Bay between New Brunswick and Maine (Figure 13-1) and Cook Inlet in Alaska (Figure 13-2). Both sides have large tidal ranges and large volumes of water that can be impounded with relatively short dams. The high and low pools at Passamaquoddy encompass 368 km² which can be contained by building a dam only 11 km long. The potential electrical generating capacity at Passamaquoddy is 1,000 MW. Cook Inlet could provide 2,600 MW from Turnagain Arm and Knik Arm using a two-pool configuration.



Source: U.S. Energy Research and Development Administration, Division of Geothermal Energy, "Tidal Power Study," EX-76-C-01-2293, March 1977.

Figure 13-2. PROPOSED TWO-POOL SYSTEM—KNIK ARM/ TURNAGAIN ARM, COOK INLET

Another excellent resource is the Bay of Fundy, on the eastern shores of Canada, where three sites could yield a total of 6,435 MW by damming off the Minas Basin, Shepody Bay, and the Cumberland Basin. The last of these, typical of the Fundy sites, would require a 3.2 km long dam to impound a 16 km long arm of the sea.

Technology

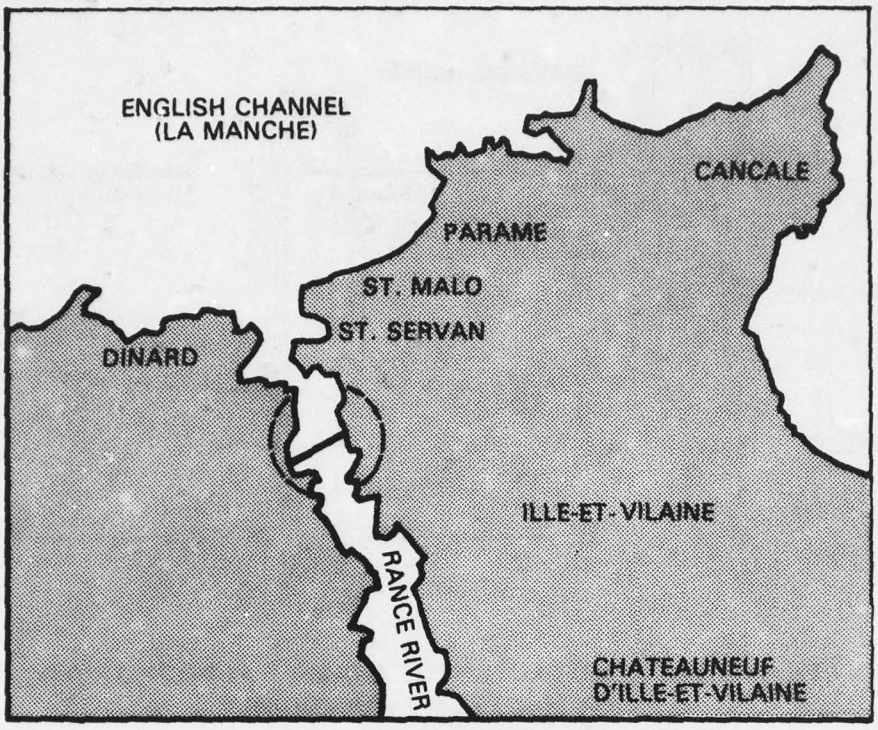
A tidal power plant consists of three basic components: the dam, the power house, and the sluices. A reservoir of water at one level is discharged to a lower level through a turbine that drives an electrical generator. Typically, the higher level pool is contained behind a dam and sluice ways to control the flow of water.

Improvements in construction techniques and generator designs have enabled engineers to design larger and more efficient tidal power plants. One such improvement is a method to close the gap between the two ends of a dam. Closing dams at potential tidal power sites is difficult because the large range between high and low tides causes extremely rapid currents, which can preclude use of normal construction techniques. The Dutch have extensive experience in building large sea walls. To close these walls, they use floating caissons with gates, which can be positioned as desired. The gates are closed simultaneously at slack water when there is no flow. The caissons are left in position and the dam completed over them. A report to the British government by the Netherlands Engineering Consultants Foundation states that the floating caisson technique is the only proved construction technique that could be used to close a dam across the Severn Estuary.[7]

Depending on the site and the power requirements, one or two pools may be preferred. The configuration at La Rance is a single pool (see Figure 13-3), while at Passamaquoddy or Cook Inlet, a double pool may be preferred (see Figures 13-1 and 13-2). In the simplest form of operation, a single pool (defined by the dam) is allowed to fill at high tide through the sluice ways. The water is confined and, at low tide, discharged through the turbines to generate electricity. To increase generating capacity, the incoming water at high tide can drive the turbines if the flow path of the water is switched through a complex arrangement of sluices. Development of reversible-flow turbines, capable of generating electricity from water flow in either direction, has greatly simplified the layout.

A further advantage was gained with the development of turbines that could also be used as pumps, with minimal loss of efficiency. The advantages of pumping water into the pool at high tide were recognized early. At high tide, the difference in level between the pool and sea is small; when the water in the pool is released at low tide, it falls through a much greater head. The same effect is produced by pumping water out of the pool at low tide, and releasing water into the pool at high tide.

Initially, the La Rance installation was designed with a conventional vertical shaft arrangement, that is, with the generator out of the water above the turbine. This design would have limited the installed capacity of the plant. Therefore, because the topography at La Rance lends itself well to a system of a single pool defined by a dam wall, with pump turbines to enhance the effective tidal range, a new group-bulb concept was used instead. This system allows the turbine to work in both directions by reversing the blade angle. A group



Source: Douglas M. Considine, ed., *Energy Technology Handbook* (New York: McGraw-Hill Book Company, 1977).

Figure 13-3. SINGLE-POOL CONFIGURATION AT LA RANCE TIDAL ENERGY PLANT

of 24 of these group-bulb turbine generators, each with a capacity of 10 MW, was installed in La Rance tidal power station. In the horizontal-bulb units, a generator is contained with a casing immersed in the flow of water (see Figure 13-4).[8] Using the generator as a motor, the turbines can work as pumps in either direction and can also operate as sluice gates. This flexibility considerably increases the efficiency of tidal power extraction.

A single-pool system such as that at La Rance cannot generate electricity on demand because it is subject to the cycle of the tides (which in most parts of the world has a diurnal and semidiurnal component). Baseload power or power on demand could be provided by a two-pool system, however, as in the Passamaquoddy scheme (Figure 13-1) and the Turnagain Arm/Knik Arm scheme (Figure 13-2). In the two-pool system, turbines would be installed between the high pool, which is filled by the high tide, and the low pool, which is drained by the low tide.

Environmental and Legal Issues

The environmental effects of generating power with tidal energy are related to the change from an open estuary of high current speeds and flushing rate to a closed pool of low currents and little vertical exchange. Within the pool, the consequences would be greater

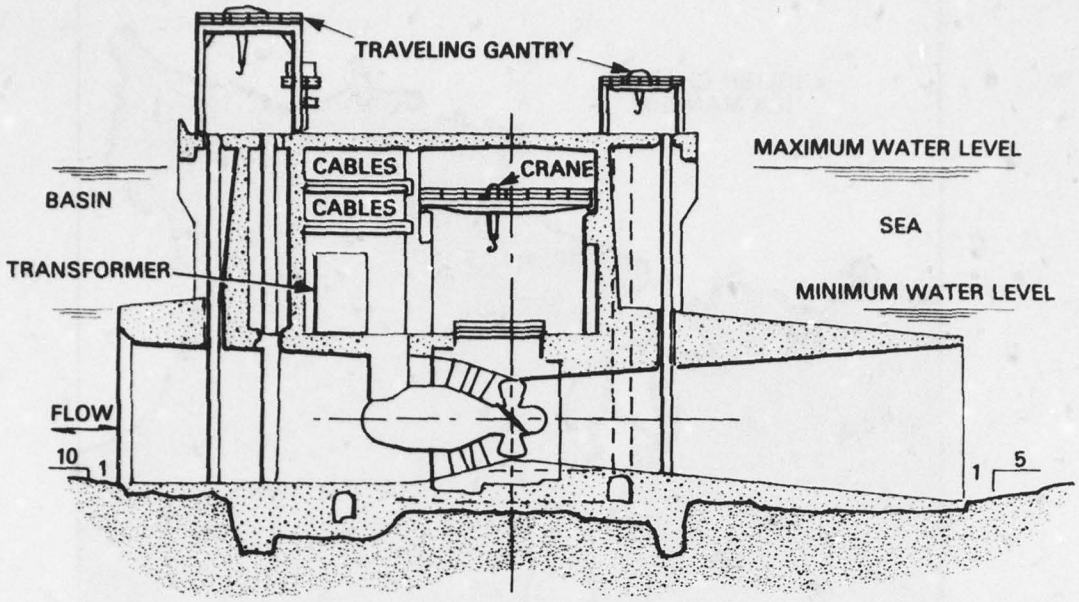


Figure 13-4. CROSS SECTION OF A POWER PLANT EQUIPPED WITH A BULB-TYPE TURBINE

stratification, lower rates of oxygen uptake, reduced surface salinity with higher summer temperatures, and lower winter temperatures. With reduced flushing rates, the transfer of river-borne pollutants to the ocean would be hindered. Sedimentation patterns would also be greatly altered. Biological changes would result from these physical changes and from the separation of the pool area from the sea, so that most species would be affected.

The free passage of shipping would be hindered by the dam, and would necessitate the introduction of locks. The presence of the dam could also affect shipping by altering tidal heights at nearby ports, resulting from changes in the resonance characteristics of the locality.

Legal issues concerning tidal power generation would be similar to those concerning dam or harbor construction. Development of the tidal energy potential at Passamaquoddy would require a cooperative arrangement between Canada and the United States.

Economics

With the increase in price of fossil fuels, tidal power is becoming an attractive alternative, but at present there are no plans to build generating plants. The economic feasibility of a tidal power plant varies with the distance of the plant from the market, the use to which the power would be put, and other factors. The more expensive, two-pool scheme, for example, could be used efficiently for pumped storage if its capacity were a significant fraction of a cyclical demand.

Recent studies by the Canadian Federal/Provincial Tidal Power Review Board indicate that a tidal power plant in the Bay of Fundy is economically feasible. A 3,800 MW tidal plant in the Minas Basin in the Bay of Fundy would cost $3.6 billion (Canadian) and generate at-site power costing 18 mill/kWh. Plants at the smaller sites at Cumberland Basin and Shepody Bay would generate power costing 22 to 30 mill/kWh. Over 30 years, the benefit/cost ratio for the Cumberland Basin site is expected to be 1.2:1.[9]

The benefit/cost ratios (for power only) at two U.S. sites range from 0.15 for Turnagain Arm in Alaska, to 0.51 for the Cobscook Bay area of Passamaquoddy,[8,10] The low ratios for Alaskan projects result partly from high construction costs and partly from the comparatively low electrical demand.

The Passamaquoddy tidal project has been studied intermittently for the last 50 years, and although it arouses widespread public interest, it is not cost-effective. (Even the best benefit/cost ratio of 0.51 for power alone, or 0.71 when supplemented benefits are considered, does not make the scheme attractive.) The British government recently came to a similar conclusion regarding the Severn Estuary project: "The engineering studies have led to predictions of very much higher costs of construction than those proposed earlier. In general terms, the economic aspects appear to have deteriorated."[7]

WAVE ENERGY

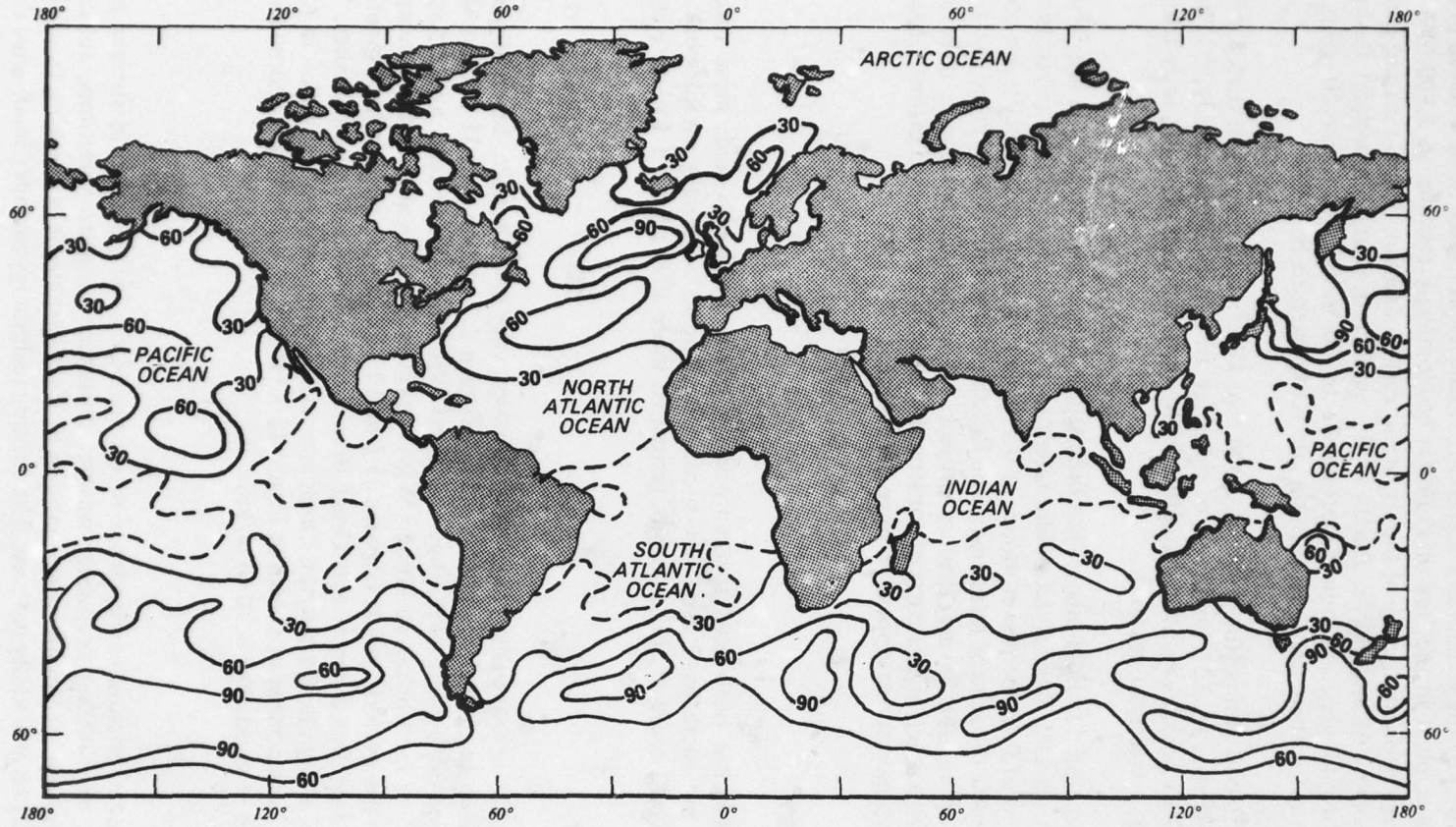
Wave power has been used for centuries to power bell-buoys and, more recently, whistle-buoys, but there have been few successful attempts to obtain useful work from ocean waves. Until recently, no concepts generated more than about 1 kW of electrical power.

Resource

Estimates of the renewable power of wind waves vary considerably, depending on the assumptions made in the calculation. A value between 2.7 million and 35 million MW is reported for renewable wind wave power summed over the ocean surface, and 2.5 million MW summed over the world's coastline.[2] Wave energy is found in abundance in temperate latitudes under the westerly winds (Figures 13-5 and 13-6); in the northern hemisphere, the west coasts of the United States and Great Britain are regarded as favorable sites. Wave power averaged along the Washington-Oregon coastline varies between 5 MW/km in August to 16 MW/km in December as shown in Figure 13-7.[8] A British estimate for annual average power available at good sites is 70 MW/km.[5]

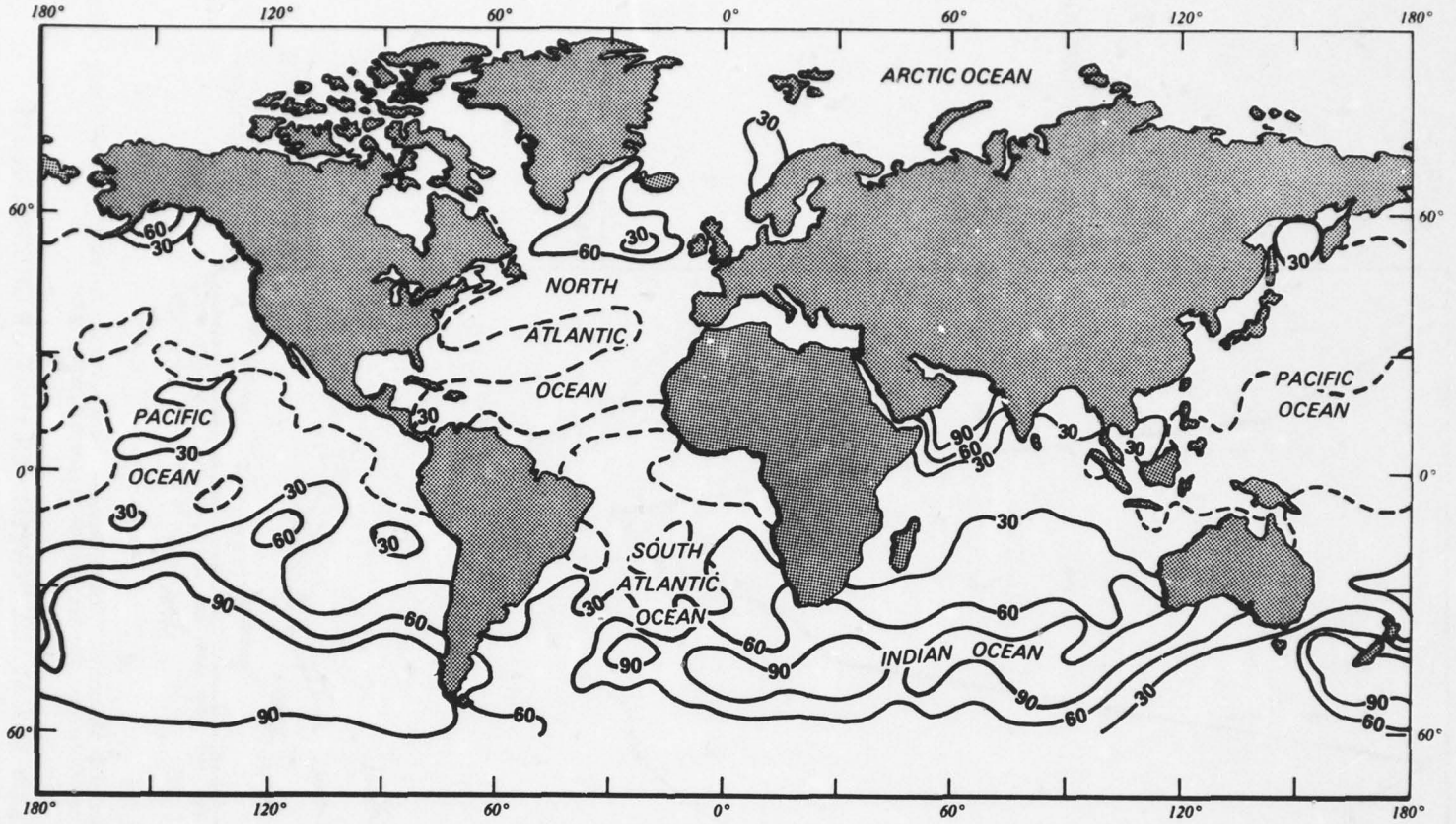
Technology

Devices for extracting energy from waves are based on: variation in surface profile (slope, height) of traveling deepwater waves, subsurface pressure variations, subsurface fluid particle motion, or unidirectional motion of fluid particles in a breaking wave, which may be naturally or artificially induced. The existing technology includes small-scale devices



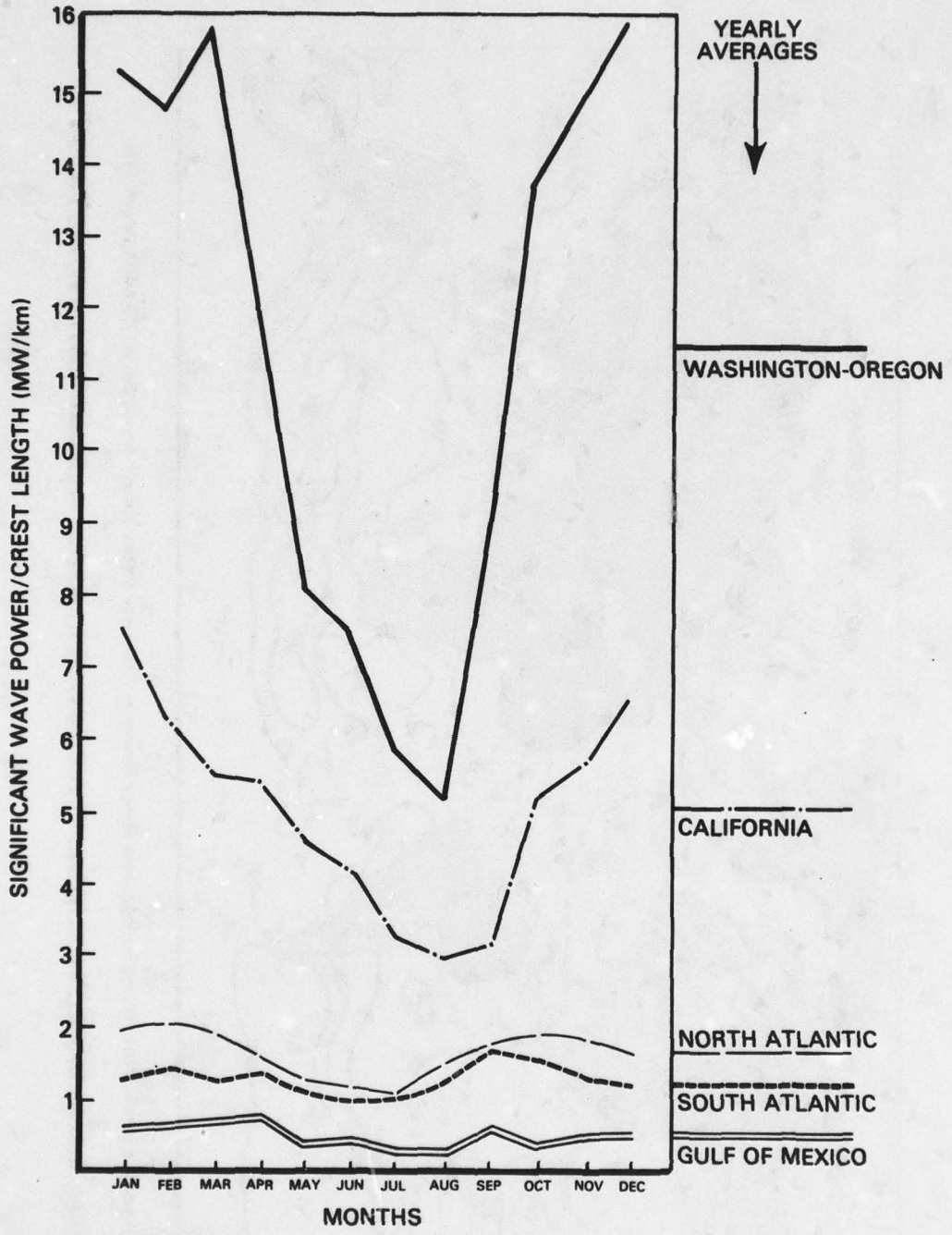
Source: The Rand Corporation, "The Potential of Indigenous Energy Resources for Remote Military Bases," Report No. 9-1798-ARPA, March 1976.

Figure 13-5. AVERAGE POTENTIAL WAVE POWER DENSITY: FEBRUARY (kW/m/WAVE FRONT)



Source: The Rand Corporation, "The Potential of Indigenous Energy Resources for Remote Military Bases," Report No. 9-1798-ARPA, March 1976.

Figure 13-6. AVERAGE POTENTIAL WAVE POWER DENSITY: AUGUST (kW/m/WAVE FRONT)



Source: Michael E. McCormick, "Salinity Gradients, Tides and Waves as Energy Sources," *Energy from the Oceans—Fact or Fantasy?* (Raleigh: University of North Carolina, 1976).

Figure 13-7. WAVE POWER PER UNIT OF CREST LENGTH

(1 kW or less) and large-scale (1 MW) units, which are being tested by the British and Japanese. Research on wave energy in the United States focuses on estimating the availability of the resource.

Small Devices

Durable small devices have been developed that can provide power for remote applications. These devices have a number of potential uses, which have not yet been fully explored.

Wave Activated Turbine Generator

The most successful wave-power device has been a wave-activated turbine generator (WATG),[11] which was first produced in 1965. Approximately 300 units were manufactured in Japan, and are now in use throughout the world. Large-scale units have been tested in Japan, and the United Kingdom is testing this and other concepts at one-tenth scale.[12]

A WATG is basically a pipe in which the surface of the sea acts as a piston to drive air past a turbine coupled to an electric generator. These devices, kept buoyant by a float, are used for powering navigational buoys and lighthouses (see Figure 13-8). Commercial models of the WATG are available with capacities up to 120 W. The main advantage of the WATG over many other wave energy devices is that the moving parts come into contact with air only, and are not subject to the biofouling and corrosion caused by contact with seawater. The air in the pipe is above sea level and is compressed as the wave passes. This compressed air is forced at high speed through a nozzle, activating the turbine to generate electricity. A system of one-way valves ensures that the turbine is turned on both the up and down strokes.

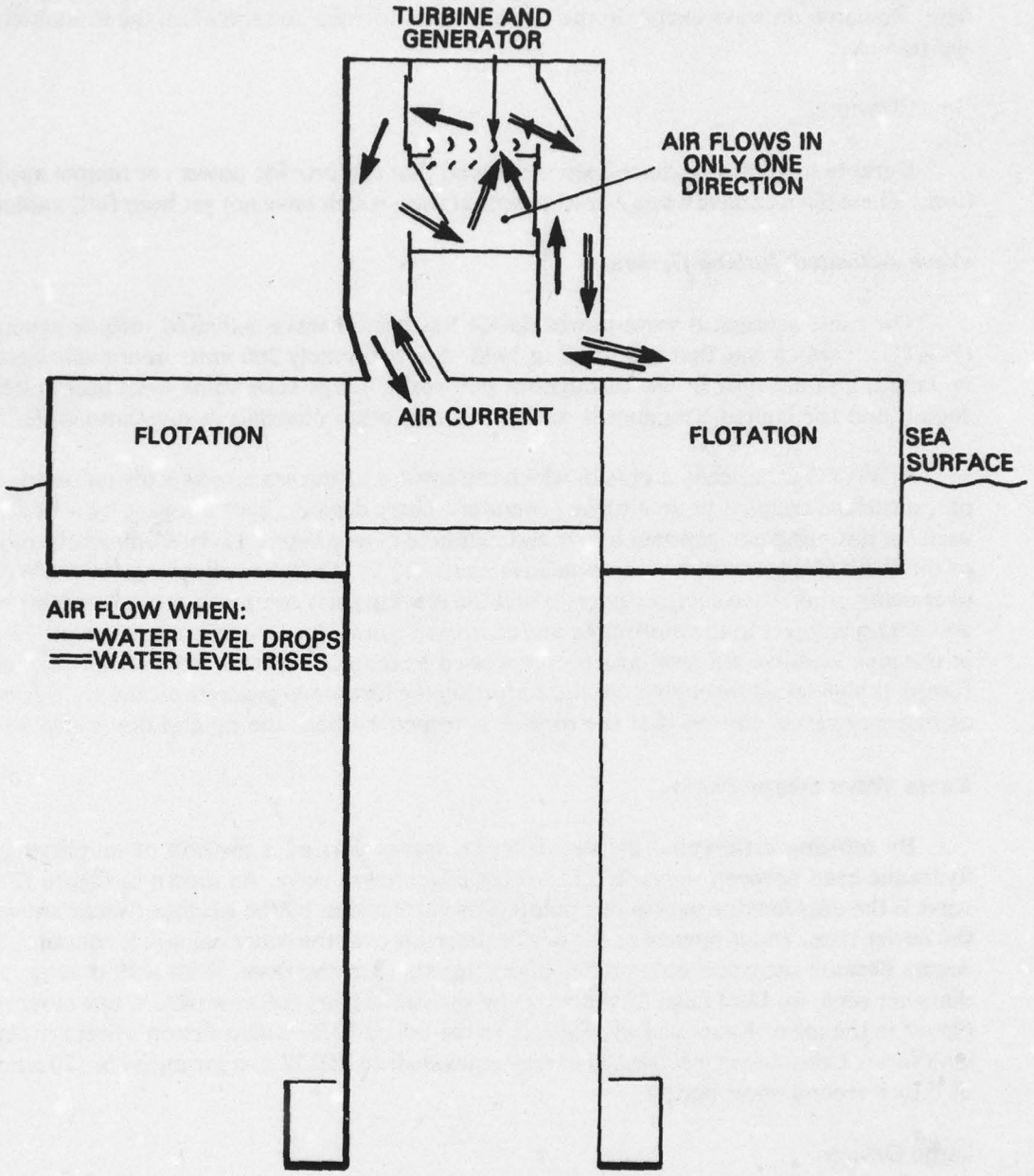
Isaacs Wave Energy Pump

By utilizing differential inertia, John D. Isaacs devised a method of amplifying the hydraulic head between the crest and trough of an ocean wave. As shown in Figure 13-9, a valve is the only moving part in this pump. The valve is shut by the weight of water above, as the device rises, and is opened as the device descends over the water column it contains. This occurs because the water column has higher inertia than the float. With a 90 m long, 5 cm diameter pipe, an 18 m head of water can be generated from 0.6 m waves. A test model was placed in the sea of Kaneohe Bay, Hawaii, in the fall of 1976, with a Pelton wheel driving an alternator. Continuous mechanical energy equivalent to 250 W was produced in 120 cm seas of 6 to 8 second wave period.

Large Devices

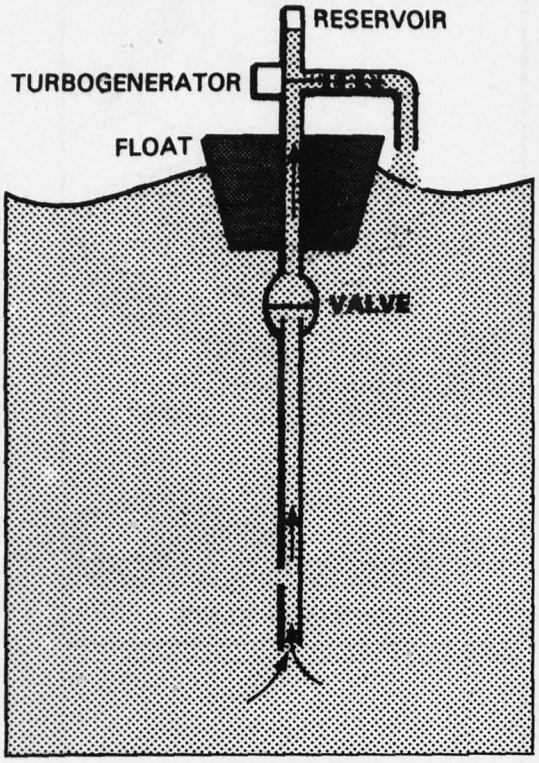
In August 1978, a 450 metric ton research platform, the *Kaimei,* was launched 4 km off Tsuruoka, Japan, and has produced 125 kW of electrical power. The principle is the same as that used in the WATG device, in that the free surface of the ocean is used as a piston to drive air past a turbine coupled to an electrical generator.[13,14] If tests are successful, a 20 MW station will be built on the same principle.

Other large-scale R&D efforts are being conducted in the United Kingdom; $5.8 million



Source: L. Masuda, "Wave Activated Generator," Transaction of the International Colloquium on the Exploration of the Oceans, Bordeau, 1971.

Figure 13-8. WAVE-ACTIVATED TURBINE GENERATOR



Source: U.S. Energy Research and Development Administration, "Wave and Salinity Gradient Energy Conversion," C00-2946-1, 1976.

Figure 13-9. ISAACS WAVE ENERGY PUMP

was allocated in 1977 to develop wave energy, and $5 million was spent prior to 1977.[6] In November 1978, the British government announced it would double the rate at which it now finances wave power research.[15]

The British Department of Energy is investigating four large-scale wave energy devices, shown in Figure 13-10. One of these devices is Sir Christopher Cockerel's invention, the "contouring raft," composed of hinged pontoons driving hydraulic pistons. A 1 kW prototype has been built.

A second device is the "nodding duck" invented by Dr. Stephen Salter of Edinburgh University. This device converts wave energy to mechanical energy using a number of cams that oscillate around a central spine, and is highly efficient. A one-tenth scale model has been built.

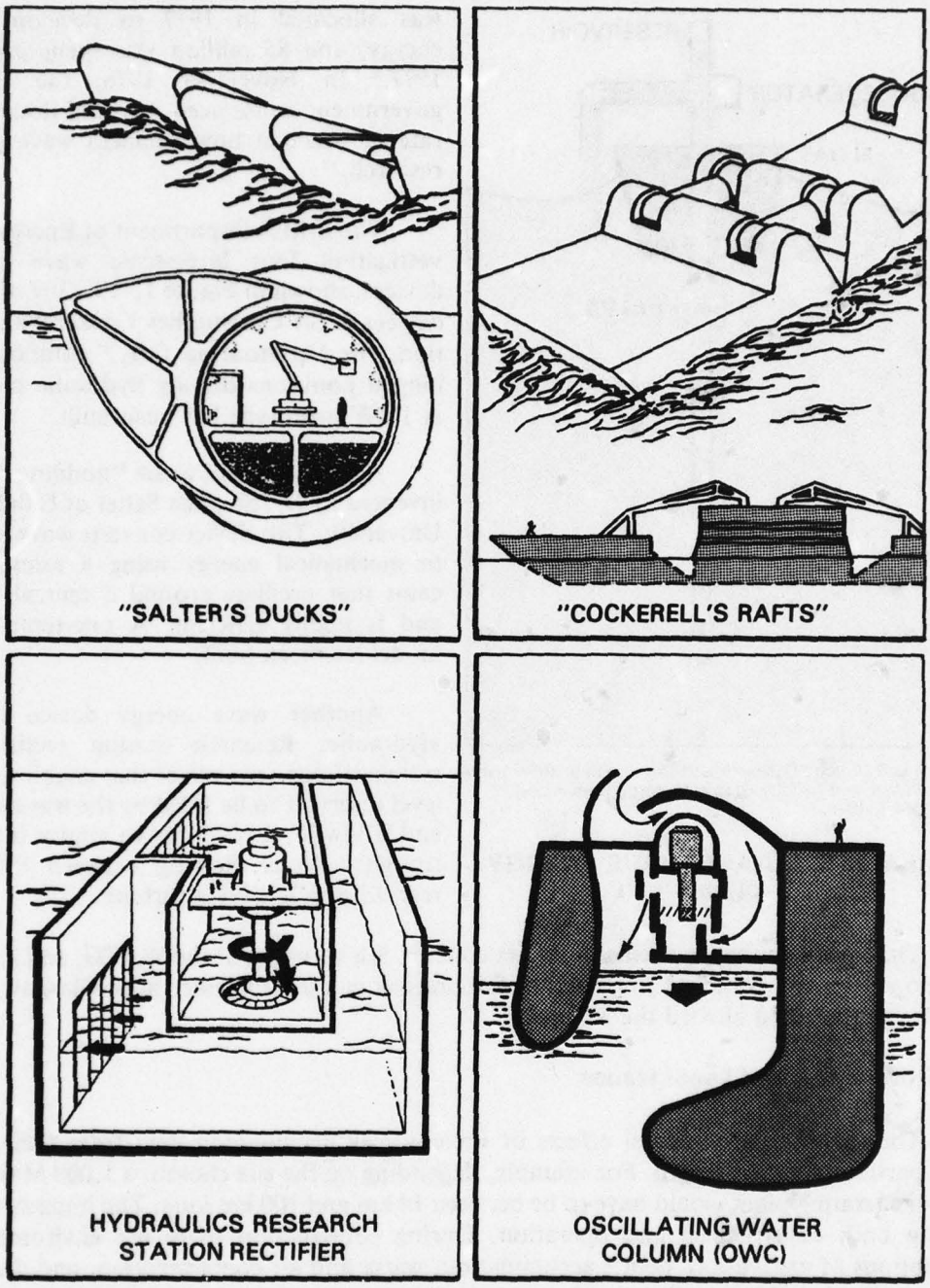
Another wave energy device is the Hydraulics Research Station rectifier, a system of one-way valves that enable a high-level reservoir to be filled by the wave crests, and a low-level reservoir to empty into the troughs. Water flowing between the two reservoirs will drive a turbine.

The fourth device, an oscillating water column, is a variation of the WATG, and is being developed by the National Engineering Laboratory at East Eilbride, near Glasgow. It is similar to that used aboard the *Kaimei.*

Environmental and Legal Issues

The major environmental effects of wave energy installations stem from their large size, particularly their length. For example, depending on the site chosen, a 1,000 MW electrical generating plant would have to be between 14 km and 100 km long. The impacts occur during both construction and operation. During construction there are environmental disruptions of excavation, debris accumulation, water and air contamination, and destruction of wildlife habitats and vegetative growth. During operation, the installation may be expected to act as a breakwater by extracting the energy from the wave. The quieter seas will drop their sediment, changing the nature of the shoreline.

Legal issues involving wave energy installations are similar to those encountered in a large civil engineering project, such as a breakwater. An added problem, however, would be that a floating structure could be set adrift and cause damage.



Note: The human figures on each device are realistically to scale.

Source: "Status Report on the Alternative Energy Sources," *ATOM*, 252, October 1977.

Figure 13-10. WAVE ENERGY DEVICES

Economics

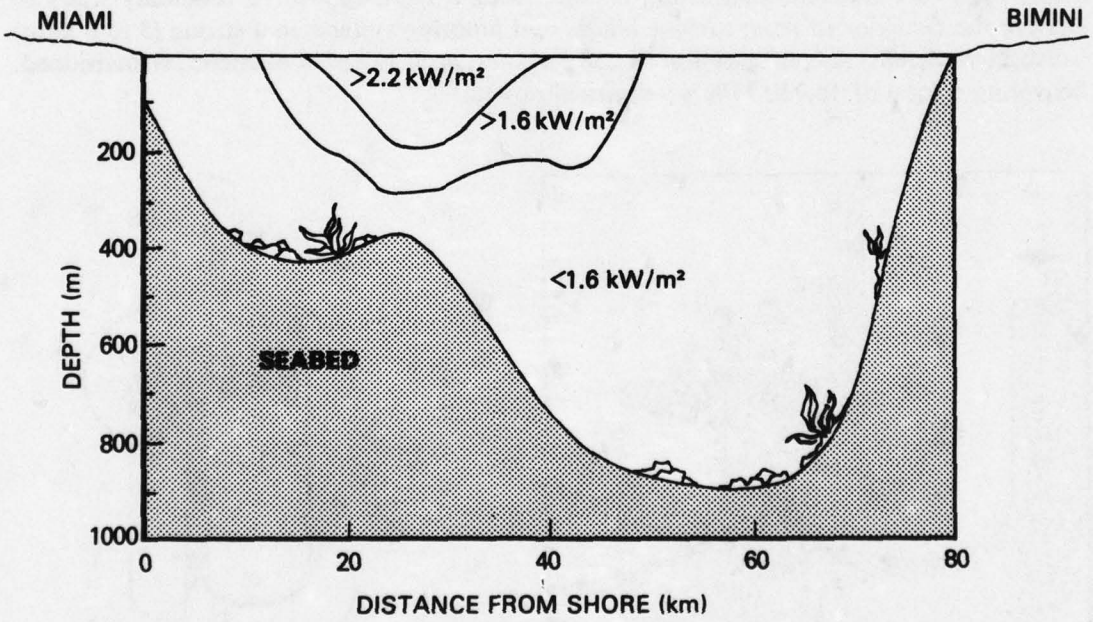
Estimates of the economics of producing electricity from ocean waves range from $400 to $3,400 per installed kW capacity and 25 to 40 mill/kWh.[8] In combination with another purpose (for example, by using the installation as a breakwater), it may be possible to generate electrical power at a competitive cost from waves. The main economic problem arises because any structure has to be designed to withstand the largest storm waves, while the prevailing waves, which would provide most of the energy, are only about one-tenth that size.

OCEAN CURRENT ENERGY

"There is a river in the ocean," said Matthew Fontaine Maury[16] in describing the Gulf Stream, and it is this ever-flowing river that proponents of ocean current power intend to harness to produce electricity. In a manner similar to hydroelectric generation, the flow of water is used to turn a wheel, which drives a dynamo.

Resource

The total kinetic power of the Florida Current is approximately 25,000 MW, with a power-density distribution between Miami and Bimini as shown in Figure 13-11. This distribu-



Source: E. V. Somers and W. E. Shoupp, "Electric Power Production from the Florida Current," *Proceedings of the MacArthur Workshop on the Feasibility of Extracting Usable Energy from the Florida Current*, H. B. Stewart, ed. (Miami: NOAA Atlantic Oceanographic and Meteorological Laboratories, 1974).

Figure 13-11. CROSS-SECTION OF POWER DENSITY IN THE FLORIDA CURRENT

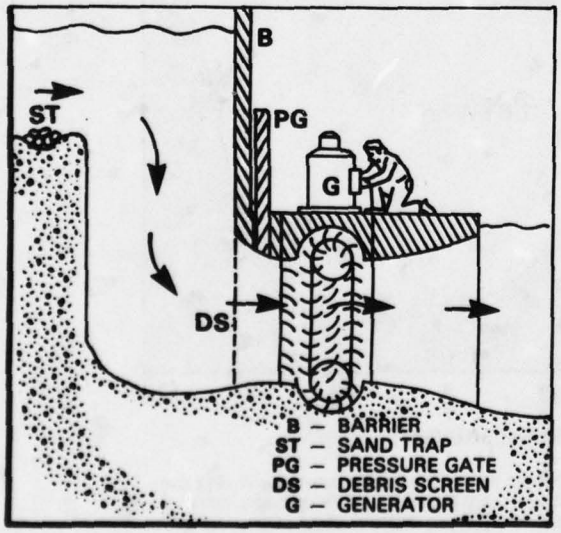
tion is similar to that found in the other major western boundary ocean currents such as the Kuroshio, the Somali Current, and the Brazil Current. The energy in these currents derives from the trade winds, and the form which the currents take on encountering continents—deep and rapid—is a result of the flow being directed toward the poles in the presence of Coriolis force.

Two major currents that derive their energy from a different source—evaporation—are found at the Straits of Gibraltar into the Mediterranean Sea and at the Straits of Bab el Mandeb into the Red Sea. Each of these could potentially produce as much as 100 MW of electricity.

Technology

The Gulf Stream attains speeds of 2.5 m/s at the surface off the coast of Florida. This low-head power is sufficient to generate electricity from a number of devices. Many devices for extracting this hydropower from the ocean have been designed, but few have been built and tested. Among the designs that have been considered are Kaplan-type turbines[17] and lifting foils[18] (Figure 13-12). (Other experimental designs are based on Savonius rotors, shown in Figure 13-13,[19] and a parachute-driven cable, shown in Figure 13-14.[20])

Existing Kaplan-type turbines could be used in the Florida Current if they could be mounted in the velocity maximum with a means of getting the power to shore. AeroVironment, Inc., of Pasadena, California, is conducting a DOE-sponsored feasibility study to analyze the behavior of large turbine blades and mooring systems in a strong (5 to 6 knot) subsurface current. A configuration of 250 turbines, each 152 m in diameter, is envisioned, delivering a total of 18,750 MW of electrical power.



Source: B. Kocivar, "Lifting Foils Tap Energy of Flowing Air or Water," *Popular Science*, February 1978.

Figure 13-12. LOW-HEAD LIFTING FOIL

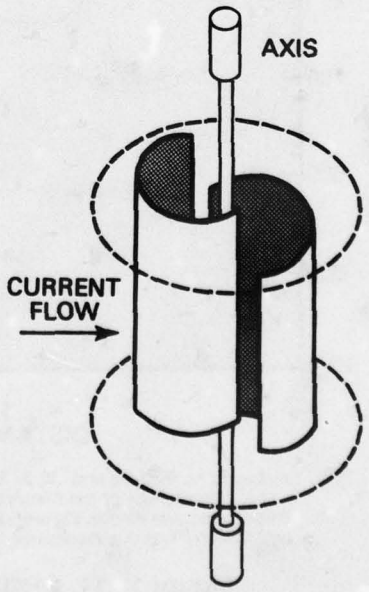
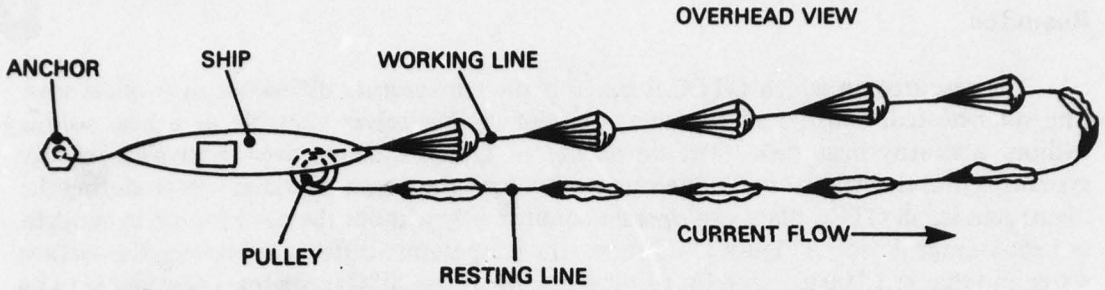


Figure 13-13. SAVONIUS ROTOR



Source: G. E. Steelman, "An Invention Designed to Convert Ocean Currents into Usable Power," *Proceedings of the MacArthur Workshop on the Feasibility of Extracting Usable Energy from the Florida Current*, H. B. Stewart, ed. (Miami: NOAA Atlantic Oceanographic and Meteorological Laboratories, 1974).

Figure 13-14. OVERHEAD VIEW OF LOW-VELOCITY CONVERTER

A lifting-foil was demonstrated in South Korea[18] at a land-based installation, and DOE, through the National Bureau of Standards Office of Energy Related Inventions, is supporting further development of this principle. A $\frac{1}{25}$ scale model is intended to lead to the testing of a full-scale device in a canal in the Turlock Irrigation District of California.[18] In view of the abundant low-head power available in rivers, and the comparative ease of river-side rather than ocean-bed construction, this would appear to be an ideal test bed site.

The problem of converting the energy in ocean currents to electricity is not so much the design of the extractor as the cost of the platform and the cable link. The engineering problems of installation and mooring can be simplified if an ocean current resource can be found close to the seabed and on the continental shelf. These conditions may exist as permanent features of the western boundary currents in favored locations. Recent work in the Agulhas Current in the Indian Ocean with side-scan sonar has located a site with severe scour, an indicator of favorable conditions for resource development.

Environmental Issues and Economics

Environmental problems that must be addressed before implementing schemes for harnessing ocean currents are related to disturbance of the ecosystem and the consequences of such disturbances. These must be assessed carefully before this source is tapped on a large scale. There is little doubt that a cost-effective marine turbine power plant can be developed since the energy source—water current—is free, and the machinery is simple.

OCEAN THERMAL ENERGY

The earth's oceans can be viewed as natural collectors, reservoirs, and distributors of solar energy. Between the Tropics of Cancer and Capricorn, the oceans intercept almost 40 percent of the solar energy reaching our planet, and as a result there is a plentiful resource of warm tropical surface water overlying denser, polar-cooled subsurface waters. By using the warm surface water as a heat source, and the cooler subsurface water as a heat sink, it is possible in principle to drive a thermodynamic engine to generate electricity. Ocean thermal energy conversion (OTEC) can be done either in a single-fluid, open-cycle system or a two-fluid, closed-cycle system.

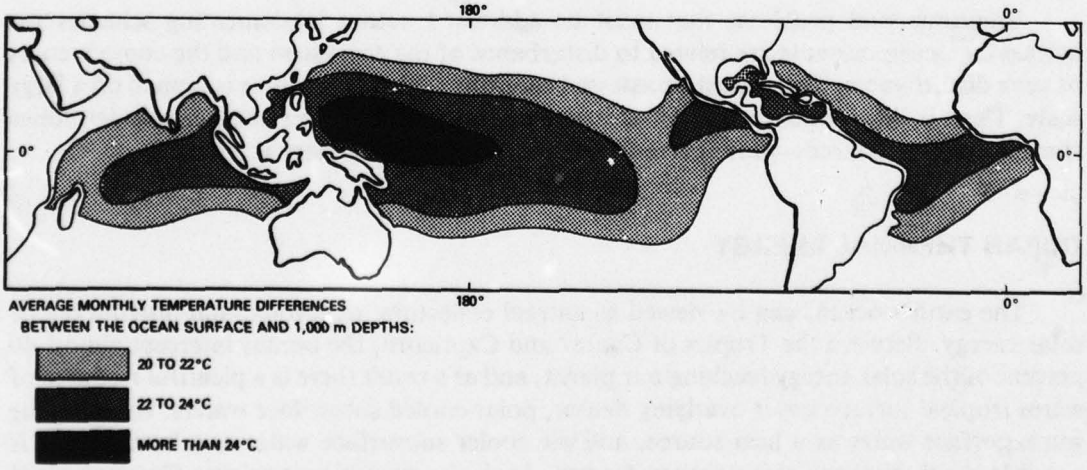
Resource

The resource on which OTEC is based is the temperature difference in tropical seas. The solar-heated, warm surface waters are not in themselves valuable as a heat source without a nearby heat sink. (The advantage of OTEC systems over most solar energy systems is that the heat stored in the surface layers of the ocean is available even during the night; that is, an OTEC plant can operate continuously without the need for direct sunlight or heat-storage devices.) Figure 13-15 shows the temperature difference between the surface water and that at 1,000 m depth for tropical oceans. If the 20 °C isotherm is considered to be the boundary of a usable resource, the OTEC resource is abundant. An area in the western Pacific Ocean of at least 7 million km² is the most favorable region because temperatures differ 24 °C or more (Figure 13-15). The thermal energy available in the ocean is difficult to quantify because of the lack of reliable estimates of renewal rates, but some values can be derived. The Gulf of Mexico, for example, can support an estimated 2,000 to 10,000 OTEC plants, each of 100 MW capacity. The ideal site conditions for the first U.S. OTEC plants are most nearly approached in Puerto Rico and Hawaii, where temperature differences are fairly high year round over large regions.

Technology

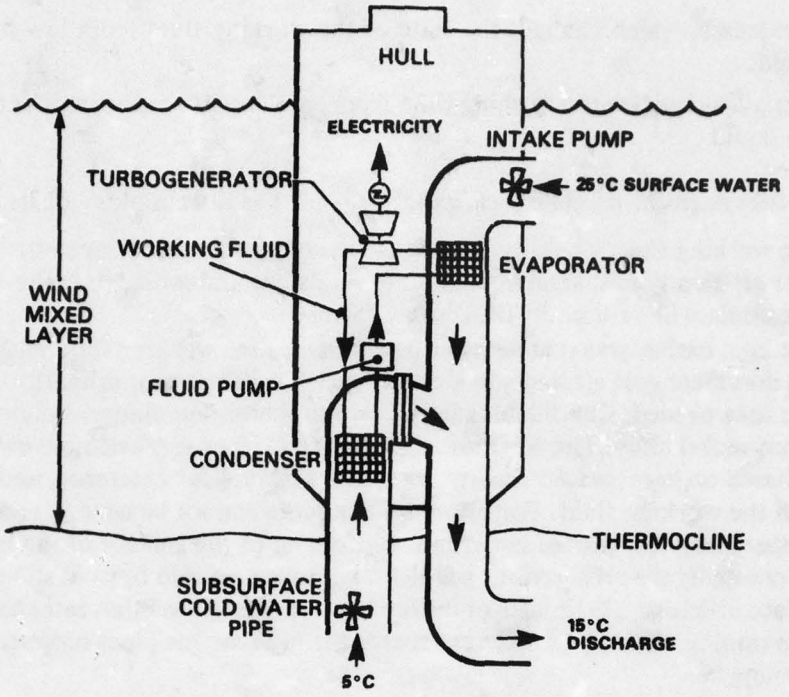
Figure 13-16 illustrates the principle of generating power from a heat source and a heat sink. In such a system, a working fluid is boiled in an evaporator; the resulting vapor turns a turbine, and it then condenses back to fluid. This is the same principle used in conventional coal- or oil-fired plants that use water as the working fluid, with the exception that the temperatures are lower and a different fluid must be used in an OTEC plant.

The thermodynamic efficiency of OTEC power plants is controlled by the available ocean water temperature differential, efficiency of the heat exchangers, fluid energy losses



Source: U.S. Department of Energy, Assistant Secretary Energy Technology, Division of Solar Energy, 1978.

Figure 13-15. OTEC THERMAL RESOURCE



Source: C. P. Duncan, D. K. Atwood, and M. C. Stalcup, "Energy from the Sea: Ocean Thermal Energy Conversion Possibilities in the Caribbean," Proceedings, CICAR II Symposium, Caracas, Venezuela, July 1976.

Figure 13-16. DIAGRAM OF AN OTEC PLANT

from pumping large amounts of water, and frictional losses incurred by the power plant machinery. Because the temperature difference between the surface and subsurface waters is so small (typically less than 24°C), the amount of energy that can be extracted per unit mass is small. Therefore, an OTEC plant must process a large amount of water to generate a significant amount of electricity. Approximately 500 m^3/s of hot water will be needed to generate 100 MW of electric power.[21] The overall efficiency in an OTEC plant is low—2 to 3 percent. This low efficiency, governed chiefly by the Carnot efficiency, can be improved by making technological advances in the heat exchanger and pumping components. Fluid frictional losses can be reduced by lining pipes with hydraulically smooth materials and reducing the potential of biofouling.

The conventional OTEC method is a closed-Rankine-cycle system (Figure 13-16). This method, which will be tested by DOE with OTEC-1, uses the following major components:

- Boiler or evaporator fueled by warm seawater to change the state of the working fluid from liquid to high-pressure gas.
- Turbine to convert the thermal energy stored in the working fluid into mechanical energy to drive an electric generator.
- Cold-water pipe and pumping system to bring the cold water from the ocean bottom to feed into a condenser.

- Condenser, which changes the state of the working fluid from low-pressure gas to liquid.
- Pumps to circulate the working fluid from condenser to evaporator and to pressurize the liquid.

Each subsystem of an OTEC closed-cycle plant has a technology of its own:

- The working fluid is required to change its state at oceanic temperatures and transfer heat efficiently and safely. Candidate fluids are ammonia, propane, and R-12/13. Ammonia will be used in DOE's test facility.
- The heat exchangers that transfer heat between the working fluid and the ocean are the dominant cost elements in a closed-cycle OTEC design, primarily because of the vast area needed. Candidate materials are titanium, aluminum, stainless steel, and a cupro-nickel alloy. The selection of heat exchangers for the demonstration plant will be based on heat transfer quality, cost, availability, life expectancy, and compatibility with the working fluid. For example, ammonia cannot be used in conjunction with copper alloys because of corrosion. Biofouling of the surface of the heat exchanger is potentially the most serious problem, because even thin films of slime considerably reduce efficiency. Estimates of biofouling and scale-formation rates have been made by pumping seawater at different speeds through sample pipes representative of heat exchangers.
- The cold-water pipe of a 100 MW OTEC plant will be up to 1,000 m long, have a diameter of 40 m, and be strong enough to be deployed and survive in the ocean 40 or more years despite corrosion and fatigue from waves and currents. Candidate materials are concrete, glass-reinforced plastic, and rubber. The test facility will use plastic, but the final decision for the demonstration plant has not yet been made.
- The turbines will be designed to operate with the selected working fluid at the low OTEC pressure differences. No exceptional difficulties are expected.
- The electric generators and pumps are considered standard items, with no new technological demands.
- The hull containing the heat exchangers, pumps, and turbine has been the subject of recent studies by DOE contractors.
- The problem of mooring a floating OTEC plant is an exceptional one, partly because of the vast size of the plant (up to 545,000 metric tons) but also because the mooring will be in the open ocean in more than 1,000 m of water. Despite the parasitic power losses it would cause, the possibility of dynamic positioning has been considered and could have advantages for a grazing plant such as that envisioned by the Johns Hopkins Applied Physics Laboratory.
- The power generated aboard an OTEC plant could either be transmitted ashore by submarine cable or used in situ for such energy-intensive processes as aluminum-smelting. The first option is attractive for plants close to a market for electricity, while the second is a possibility in the thermally rich area of the Pacific Ocean between the bauxite mines of Australia and the U.S. market. Another possibility is to use the electricity to generate hydrogen, which could be conveyed ashore either by tanker or pipeline.

DOE's FY 1979 budget for OTEC is about $35 million; the major item is the test facility, OTEC-1. Global Marine Development Company has been awarded $25.4 million to design and construct OTEC-1, which will have 1 MW capacity; $17.3 million is allocated for 3 years of field trials, which will begin in 1980 off Hawaii. A T-2 tanker, the *Chepachet,* will be used as the test platform.[22] A 122 cm diameter polyethylene pipe will be used as the cold-water pipe to reach 700 m or more below the surface.

OTEC economics and commercialization, environmental issues, siting, ocean engineering, power system development, heat exchangers, and biofouling and corrosion, have been studied extensively.[23] Active site survey work before OTEC-1 is installed is being done off Keahole Point, Hawaii, near the Natural Energy Laboratory of the University of Hawaii. The Punta Tuna site, is being studied as an alternative by the University of Puerto Rico's Center for Energy and Environmental Research.

Environmental and Other Issues

The question of rights and jurisdiction for the international waters that fuel OTEC plants has not been answered. The Law of the Sea Conference in 1977 considered the question, but did not resolve it; the 220 km offshore limit is unofficially recognized, however. Coast Guard regulations, similar to those in force for drilling rigs and other semipermanent structures, will apply to OTEC plants.

DOE's studies of environmental effects of OTEC plants have included such considerations as the presence of the structure itself, its action as an artificial reef and its concomitant alteration of the local ecological balance, and the effects on the biota of the intakes and discharge.[24] For example:

- *Ocean water mixing*—that is, the effects on the local and downstream environment of the discharges—has received considerable attention. The discharges should be mixed to avoid surface contamination of the hot water resource, and released below the thermocline. In effect, this would introduce a new water mass with distinct and new temperature and salinity characteristics having unknown effects on biota.
- *Metallic discharges* of copper, nickel, or titanium, caused by the flow of seawater past the heat exchangers, could affect the foodchain.
- *Impingement or entrainment* of marine biota can occur on the intake screens and heat exchangers. The effects of pressure and temperature changes on marine biota are also of concern.
- *Use of biocides* to prevent biofouling of the heat exchangers, even if dilute, will result in the introduction of large quantities of biocide to the environment because of the vast quantity of water used.
- *Working fluid leaks* of ammonia—especially in the presence of chlorine—would cause severe chemical stress to marine organisms.
- *Climatological effects* of extracting heat from the surface waters of the ocean and liberating this heat on the land mass (when used as fuel) or in the ocean depths (from the discharges) could cause problems. This aspect is being studied by numerical models on a computer.

- *Worker safety,* including such considerations as the dangers normally encountered on structures such as drilling rigs, but also including contacts with the working fluids and biocides.

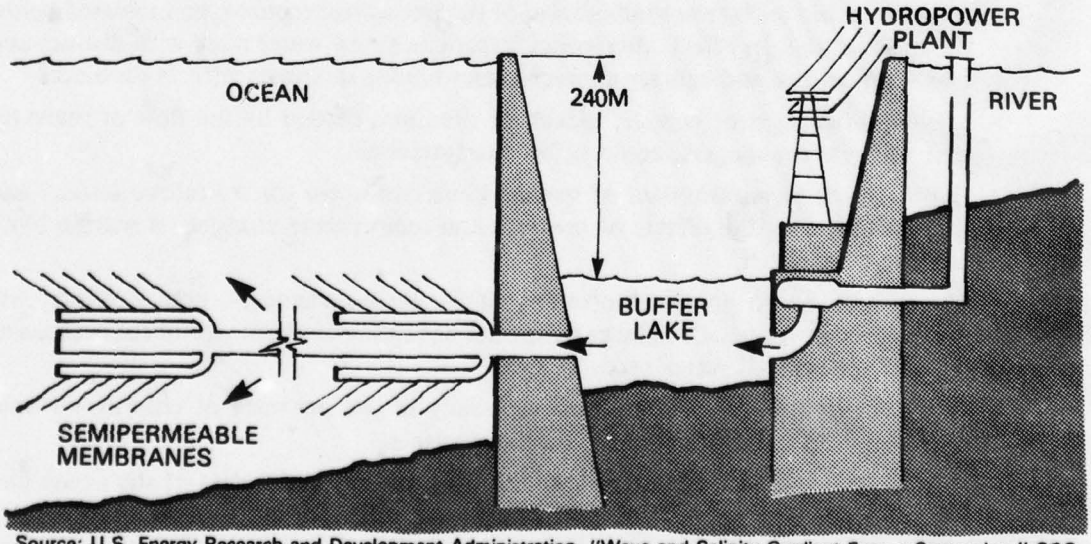
Economics

The economics of generating electricity with OTEC systems are site-dependent for a number of reasons. The price of electricity in the tropical regions of the world is often dependent on the local price of a single fuel, so that the cost-effectiveness of an OTEC plant varies from place to place.

The distance from shore of the cold water resource is a major factor in determining the costs. In Puerto Rico and Hawaii, for example, the underwater cable would be less than 3 km long, but in the Gulf of Mexico, the cable may have to be 250 km long, with attendant increased costs. The value of the resource itself is not determined solely by its physical characteristics, but also by its distance from a market and the construction site. For example, although the richest resource in the Pacific Ocean lies to the west of Hawaii, it is far from industrial centers. Therefore, the island sites of Hawaii and Puerto Rico will probably be developed first. For sites with a temperature difference of 22 °C, a commercial OTEC plant would cost $2,000 to $2,500 per kW installed, and would generate electricity costing 40 to 50 mill/kWh.[25]

SALINITY GRADIENT ENERGY

The salinity difference between the fresh river water and the saline ocean water at a river mouth is equivalent to an osmotic pressure of as much as 240 m of head. Figure 13-17



Source: U.S. Energy Research and Development Administration, "Wave and Salinity Gradient Energy Conversion," COO-2946-1, 1976.

Figure 13-17. METHOD FOR EXTRACTING SALINITY POWER

illustrates how this principle could be used to produce electrical power by generating a pressure-head using osmosis and conventional hydroelectric generators.

Recovery of this energy would require construction of at least two dams at the river mouth and excavation of the space between them to a depth of at least 240 m. Any fresh water entering this excavation would be removed by osmosis through the semipermeable membranes that protrude in a very large network into the ocean. River water is allowed to fall past the hydroelectric generators at a rate equal to that at which fresh water is diffused out of the intramural cavity. However, membranes are too expensive at present for this to be a cost-effective way of producing electricity. Also, the membranes are fouled very easily by any sediment or organic matter in the river water.

More sophisticated methods of converting salinity gradient energy to usable energy would allow the osmotic pressure head to be developed in a pressure vessel.[26] Research continues on the development of semipermeable membranes for use in the treatment of industrial water. The two configurations commonly used are hollow fiber and spiral-wound flat film permeators of cellulose acetate or an aromatic polyamide. Both types are used in commercial reverse-osmosis desalination systems. If the cost of these systems continues to decrease, the generation of electrical energy from salinity gradients may become a reality rather than speculation.

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14. HYDROGEN

Hydrogen is the simplest, lightest, and most abundant element in the universe. In the earth's crust, hydrogen is the ninth most abundant element by weight, existing mainly as a constituent of water. Hydrogen is present in all living organisms and in most organic compounds.

Because it is abundant and clean-burning and because its heating value per unit mass is greater than that of any other chemical fuel, hydrogen has great potential as an alternative fuel. Apart from hydrogen-welding, the best-known use of hydrogen as fuel is in the space program as high-energy rocket fuel. The National Aeronautics and Space Administration (NASA) indicated that development and support flight operations in 1978 would consume 23 million pounds of hydrogen, with an annual demand of 20 million pounds expected when the space shuttle begins operating in the 1980s.[1]

Hydrogen is applicable as a fuel in all use sectors. Considerable work, dating from the late 1920s, has been done on using hydrogen in internal combustion engines. This use of hydrogen appears to be possible by applying fuel injection and proper ignition timing. No concerted effort is being made to use hydrogen as a motor fuel, but efficiencies reported for hydrogen are 50 percent greater than efficiencies of gasoline engines.

Because it is economically attractive, the first major use of liquid hydrogen fuel may be in jet-aircraft engines. However, handling and onboard storage of liquid hydrogen is a serious problem for any volume-limited vehicle. An experimental cargo airline using liquid-hydrogen-powered aircraft is proposed for operation between the United States, Europe, and the Middle East by 1986.[1]

Stored hydrogen can be used to generate electrical energy on demand. Gas turbine systems can be converted to hydrogen without great difficulty; for base loading, the overall thermal efficiency of these systems can be increased to as high as 55 percent by supplying pure oxygen for combustion. Hydrogen is also the ideal fuel for efficient production of electricity in fuel cells (see Chapter 15). Another use of hydrogen is as a basic component of conversion processes that produce synthetic hydrocarbon fuels.

Despite hydrogen's potential as a fuel, the percentage of hydrogen now used for fuel and miscellaneous purposes (such as preparing foodstuffs, nylon, and polyurethane or manufacturing semiconductors and float-glass) is small (7 percent in 1973). Most hydrogen produced in the United States (about 1 quad per year) is used on-site in petroleum refining (see Chapter 2) and in the production of ammonia and methanol.[2]

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HYDROGEN SUPPLY AND DEMAND

Worldwide production and use of hydrogen has more than tripled over the past four decades. In 1975, the United States produced and consumed about one-third of the 18.9 million metric tons of hydrogen produced in the world. World and U.S. hydrogen supply-demand relationships are provided in Table 14-1. Production of hydrogen in the United States is difficult to estimate, because most hydrogen is used directly in producing other materials, with only small amounts being marketed. In general, about 47 percent of the hydrogen produced in the United States in 1975 was used in petroleum refining, 36 percent in manufacturing anhydrous ammonia, and 10 percent in producing methanol. These uses normally are supplied by captive (on-site) hydrogen production units. Of the remaining 7 percent of the total produced, no more than 0.5 percent was available for use as fuel.

Table 14-1. HYDROGEN SUPPLY-DEMAND RELATIONSHIPS

Distribution	1964		1970		1975		1980[a]	
	scf × 10^9	Metric Tons × 10^3	scf × 10^9	Metric Tons × 10^3	scf × 10^9	Metric Tons × 10^3	scf × 10^9	Metric Tons × 10^3
World production								
United States	1,200	2,972	2,120	5,372	2,515	6,233	2,957	7,321
Rest of the world	1,575	3,900	3,940	9,755	5,145	12,739	6,718	16,634
Total	2,775	6,872	6,060	15,127	7,660	18,972	9,675	23,955
U.S. demand pattern								
Petroleum refining	375	929	900	2,228	1,080	2,674	1,296	3,209
Chemicals								
Ammonia	596	1,476	936	2,318	1,075	2,662	1,235	3,058
Methanol	103	255	127	438	180	446	183	453
Cyclohexane	27	67	29	72	29	72	29	72
Benzene	15	37	7	17	15	37	32	79
Hexamethylene-diamine	–	–	12	30	15	37	19	47
Aniline	3	7	5	12	5	12	5	12
Naphthalene	10	25	9	22	7	17	7	17
Oxo alcohols	4	10	6	15	6	15	6	15
Other chemicals	12	30	19	47	23	57	28	69
Total	770	1,907	1,150	2,971	1,355	3,360	1,544	3,822
Miscellaneous uses								
Hydrogenation of oils	7	17	7	17	10	25	14	35
Liquid hydrogen	21	52	21	52	14	35	9	22
Direct reduction	–	–	6	15	18	45	54	134
Other	27	67	36	89	38	94	40	99
Total	55	136	70	173	80	199	117	290
Total U.S. demand	1,200	2,972	2,120	5,372	2,515	6,233	2,957	7,321

[a]Estimated.

Source: Daniel C. Adkins and Robert J. Jaske, "Hydrogen," *Mineral Facts and Problems* (Washington, D.C.: Bureau of Mines, U.S. Department of the Interior, 1975).

U.S. annual demand for hydrogen is forecast to range from 22 million to 69 million metric tons (8.8 trillion to 28 trillion scf) by 2000. The principal end uses of hydrogen in 2000 are expected to be in synthetic fuel processing, chemicals, and petroleum refining. The large consumption of hydrogen in synthetic fuels industries will be a direct outgrowth of the major thrust anticipated toward satisfying U.S. energy requirements in the 1980s and 1990s. Conversely, lower national growth rates or unexpected breakthroughs in other forms of energy uses could lessen production capacity expansion requirements. Annual hydrogen demand by the rest of the world in 2000 is forecast to reach 33 million to 105 million metric tons (13.4 trillion to 42.5 trillion scf).[3]

HYDROGEN CHARACTERISTICS

Selected physical and chemical properties of hydrogen are shown in Table 14-2.[4] Figure 14-1 compares hydrogen's energy per unit mass to that of other chemical fuels and also illustrates that hydrogen's volumetric heating value is relatively small. As shown in Figure 14-1, hydrogen's heating value per unit mass is over twice that of methane, but its heating value per unit volume is only about one-third that of liquid hydrocarbons.[5]

Table 14-2. PROPERTIES OF HYDROGEN

Property	Value
Atomic weight	1.00797 g/g-mole
Boiling point	20.4 K (−252.77°C)
Heat of vaporization[a]	107 cal/g (192.6 Btu/lb)
Liquid density[a]	0.071 g/cm³
Gas density[b]	0.0899 g/l
Critical temperature	33.3 K (−239.9°C)
Heat of transition, ortho- to parahydrogen	168 cal/g (302.4 Btu/lb)
Heat of combustion	29,000 cal/g (52,200 Btu/lb)
Flame temperature	2,483 K (2,210°C)
Autoignition temperature	858 K (585°C)
Flammability limit in air	4 to 74 percent
Flame propagation rate in air	2.68 m/s

[a]At 20.4 K.

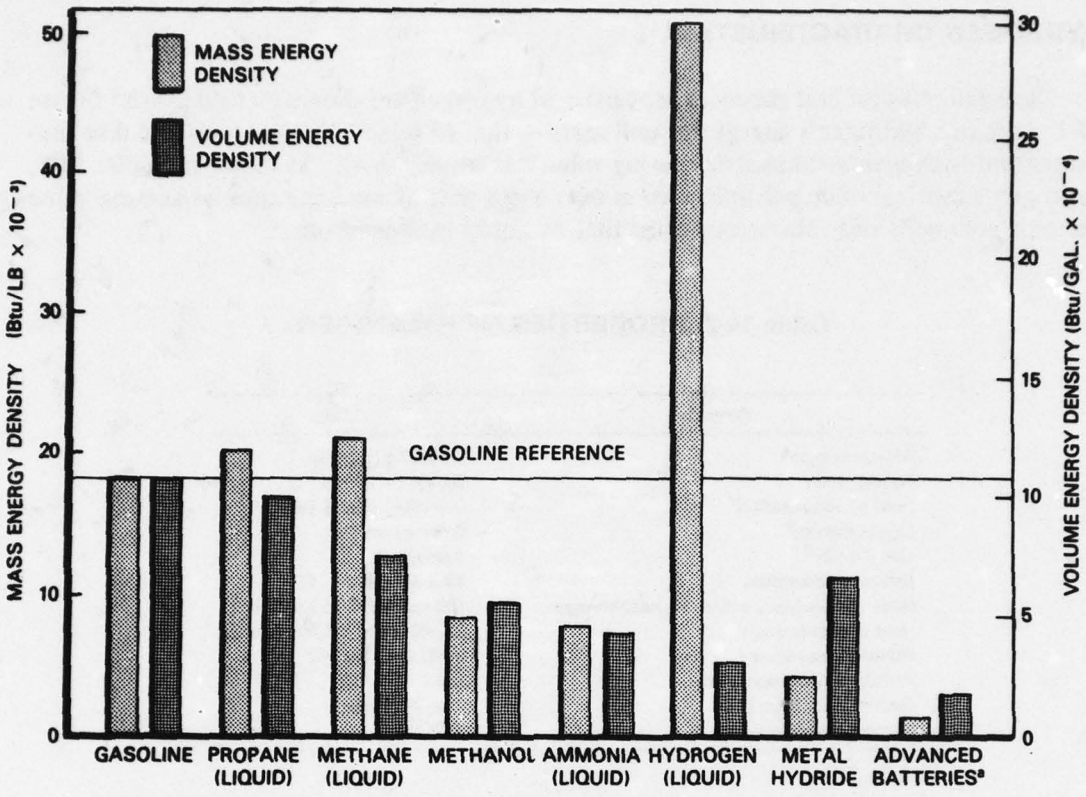
[b]At 0°C and 1 atm.

Source: Robert M. Reed, "Hydrogen," *Energy Technology Handbook* (New York: McGraw-Hill Book Company, 1977).

The low density and viscosity (which reduce friction losses) and high thermal conductivity and heat capacity of hydrogen have led to its use as a coolant to increase generator efficiency. Because of hydrogen's high adiabatic flame temperature, the high specific impulse of hydrogen/oxygen systems compared to hydrocarbon/oxygen systems, and the low molecular weights of the exhaust gases, liquid hydrogen is a prime fuel for rocket propulsion.

Hydrogen can be combusted using one of two methods: conventional burners modified to account for the particular physical and chemical properties of hydrogen, or catalytic (or surface) combustion, which can occur well below the equilibrium flame temperatures (for example, at 100°C instead of 2,000°C) and thereby avoid the formation of nitrogen oxides. Catalytic burners eliminate the open flame (particularly serious for hydrogen since the flame is invisible) and produce only water vapor, eliminating the necessity of venting the exhaust gases. Catalytic space heating systems are decentralized and resemble electrical appliances in flexibility.

One of the most important factors in all aspects of hydrogen utilization is the compression of gaseous hydrogen to desired pressure levels for storage, transmission, and distribution. Hydrogen's low molecular weight and low viscosity make any compression work very energy-intensive and render most conventional compressor designs unsuitable for hydrogen



[a]Includes adjustment for different energy conversion efficiencies.

Source: Daniel N. Lapedes, ed., *Encyclopedia of Energy* (New York: McGraw-Hill Book Company, 1976), p. 377.

Figure 14-1. ENERGY DENSITY OF CHEMICAL FUELS

usage. Embrittlement of many high-strength steels caused by hydrogen diffusion into the metal's molecular structure creates problems in highly stressed compressor parts.[6]

Since hydrogen is a gas (except at extremely low temperatures), storage is a problem. Liquefaction is costly and difficult because of hydrogen's extremely low critical temperature. At room temperature, hydrogen gas is composed of 75 percent orthohydrogen and 25 percent parahydrogen. Orthohydrogen is a form in which the two protons in the hydrogen molecule spin in the same direction; in parahydrogen, the two protons spin in opposite directions. At the boiling point of liquid hydrogen (−253 °C), thermodynamic equilibrium is achieved when the hydrogen is 99.79 percent parahydrogen. Conversion from the ortho to the para state is a second-order reaction. The energy lost in reducing the temperature of hydrogen (21 °C) at standard conditions to the temperature at which hydrogen enters the liquid phase (−253 °C) is 5,007 Btu/lb of hydrogen; an additional 192 Btu/lb (heat of condensation) must be removed to liquefy the hydrogen and another 302 Btu/lb (heat of conversion) to shift from the ortho to para state. If hydrogen is liquefied without conversion to the para state, boil-off from the spontaneous conversion will amount to about 18 percent in 24 hours and 50 percent in a week.

Hydrogen can be obtained virtually 100 percent pure, if required, although more than 98 percent of the hydrogen produced is of low purity (less than 99.5 percent by volume) for reasons of economy; the normal purity range is 95 to 98 percent. Impurities include water, oxygen, argon, nitrogen, hydrocarbons, carbon dioxide, carbon monoxide, phosgene, and mercury vapor.

SOURCES OF HYDROGEN

Natural gas, liquid hydrocarbons, coal, and water are sources of hydrogen. Typical bituminous coals contain about 5 weight percent hydrogen. Natural gas averages about 25 percent hydrogen content, and water is composed of slightly more than 11 percent. These weight percentages are small, but because of the abundance of coal, natural gas, and water, they represent vast quantities of hydrogen.[3]

All hydrogen produced commercially requires the use of some form of energy. Electrolysis is the simplest method for producing hydrogen, but it is also the most expensive method. Most hydrogen today is obtained by steam reforming of natural gas or partial oxidation of petroleum; however, increased costs and reduced availability of these feedstocks will make steam-oxygen gasification of coal the major source of hydrogen in the near term. Coal gasification is expected to be the least costly large-scale source of hydrogen for many years.[7] Other methods of producing hydrogen are thermochemical splitting and direct thermal decomposition of water, both requiring the addition of heat energy.

Steam Reforming of Hydrocarbons

One of the two widely used methods of producing hydrogen is catalytic steam reforming of hydrocarbon feedstocks, ranging from methane to naphtha feeds.[4,8] In catalytic steam reforming, preheated and desulfurized hydrocarbon feed mixes with steam over a nickel or nickel-vanadium catalyst to produce synthesis gas (hydrogen and carbon monoxide). The overall reaction is endothermic, and occurs between 650 and 980°C at 270 to 600 psi. The carbon monoxide is converted catalytically to additional hydrogen and carbon dioxide in water-gas shift reactors. The carbon dioxide is removed, leaving less than 0.2 percent carbon dioxide in the gas. The remaining carbon dioxide and carbon monoxide are converted to methane, the main impurity in the product hydrogen.

Considering all the energy inputs needed to achieve complete reformation, the process is only about 70 percent efficient.[7] Furthermore, to achieve 98 to 99 percent hydrogen purity, more stringent operating conditions are required during steam reforming and carbon dioxide removal than are required to produce 95 to 97 percent hydrogen.[8,9] The process has been operated at pressures above 600 psi to permit more effective heat recovery and reduce compression costs of the hydrogen product.

The largest hydrogen production facility in the world uses natural gas steam reforming to supply hydrogen at a production rate of 60 ton/day. This facility is operated by the Linde Division of Union Carbide Corporation in Sacramento, California.

Partial Oxidation of Hydrocarbons

The other common method of producing hydrogen from hydrocarbons is by partial oxidation of liquid hydrocarbons, with or without a catalyst, depending on the feedstock and process used.[4,10] In this two-stage process, preheated hydrocarbon, steam, and oxygen are fed through one or more burners to a refractory-lined combustion chamber and react (at temperatures ranging from 1,260 to 1,480°C and pressures ranging from 150 to 880 psi) to form carbon oxides and hydrogen. A typical example is:

$$C_6H_{14} + 3O_2 \longrightarrow 6CO + 7H_2 \text{ (exothermic)}.$$

The heat released in this reaction is used in the subsequent shift reaction of carbon monoxide with steam (as in steam reforming of hydrocarbons) to increase the yield of hydrogen:

$$CO + H_2O \longrightarrow CO_2 + H_2 \text{ (slightly exothermic)}.$$

As in steam reforming of hydrocarbons, operation at pressures above 600 psi permits more effective heat recovery and reduces compression costs. An important advantage of the noncatalytic partial-oxidation processes is the flexibility to operate with feedstocks ranging from methane to heavy fuel oil. This is offset, however, by process requirements for a plant that supplies pure oxygen.

Coal Gasification

To produce hydrogen from coal, coal is gasified by reacting it with steam and oxygen:

$$3C + 2O_2 \longrightarrow CO_2 + 2CO \text{ (exothermic), and}$$

$$3C + 3H_2O \longrightarrow CO + CO_2 + H_2 + CH_4.$$

The synthesis gas produced is converted in a shift reactor to increase the hydrogen yield. Because materials in the coal feedstock can poison the catalysts, extensive coal preparation is required to remove contaminants. In addition, the need for an oxygen supply makes this process expensive.[9] Any coal gasification process being developed to produce synthetic natural gas can be used to produce hydrogen by changing the operating conditions for the final shift reaction step. Additional information on coal gasification is in Chapter 4.

Presently, two processes are available commercially for gasifying coal with steam and oxygen.[11-13] If followed by carbon dioxide removal and liquid methane wash, the Lurgi process can produce essentially pure hydrogen. Using the Koppers-Totzek process, coal is converted by partial oxidation to produce a raw gas that contains 53 percent carbon monoxide and 34.5 percent hydrogen.

A coal gasification method using air instead of oxygen, the Stoic process, also is available commercially.[14] This process will be used in the nation's first commercial plant designed to produce hydrogen from coal. The plant will be built in Forest City, Iowa, by Winnebago Industries, Inc., to convert 324 tons of Iowa coal per day to 12.6 million scf (4.1 billion Btu) of hydrogen. The hydrogen will be used to generate electricity for Forest City, Iowa (population 4,500); provide all space heating, electricity, and gas for Winnebago facilities; and power 100 to 200 private cars adapted for hydrogen fuel.

The only project sponsored by the U.S. Department of Energy (DOE) for large-scale production of hydrogen from coal is the Air Products and Chemicals, Inc., project to design, construct, and operate a facility near Baytown, Texas, to produce 29.5 million scf/day of hydrogen (99 percent purity) by gasifying 1,210 ton/day of Texas lignite. Two Koppers-Totzek gasifiers will be used, and the hydrogen produced will be distributed through existing pipelines to industries in the area; 7 million scf/day of carbon monoxide also will be produced. The projected cost of the facility is about $100 million, of which DOE will share 50 percent.

Electrolysis of Water

Electrolysis of water, which produces a very pure hydrogen product, is currently the only commercial method available that does not require fossil fuels for tonnage hydrogen production.[4,15] The hydrogen is produced from water by passing a direct electric current between electrodes immersed in an electrolyte contained in a suitably positioned cell. The water splits into positive (hydrogen) and negative (oxygen) ions, which migrate to and collect at the cathode and anode, respectively. A molecule of hydrogen gas at the cathode forms when an electron adds to each of two hydrogen ions and the resulting hydrogen atoms combine. The electrolyte is circulated through the cell to correct shifts in anolyte and catholyte concentrations and to remove excess heat resulting from losses due to overvoltage in the cell. The gas produced is extracted in separators, washed, and dried.

Ideally, applying 1.47 volts at 25 °C would generate hydrogen and oxygen isothermally with 100 percent of the electrical energy converted into the fuel value of the hydrogen. In practice, electrolysis cells have efficiencies of 60 to 70 percent, but prototype models operating at high pressure result in efficiencies up to 85 percent. Cell efficiency can be increased by operating at higher temperatures; advanced designs can be expected to have higher efficiencies than present cells. However, since the process uses electricity produced at about 40 percent efficiency, the overall net efficiency of a 90 percent conversion process is only 36 percent.

All large-scale water electrolysis plants are built following a multimodule concept, each module having a power rating of 1 to 2 MW. The electrolyte is aqueous potassium hydroxide (20 to 30 percent); the cathode is iron and the anode is nickel or nickel-plated iron. Two types of cells are suitable for large-scale hydrogen production: unipolar (tank type) and bipolar (filterpress type).

The unipolar cell (manufactured by Electrolyzer Corporation) has a lower efficiency and requires more space than the bipolar cell. The Lurgi bipolar alkaline cell is the only large-scale electrolyzer in commercial service, but Teledyne's alkaline bipolar technology is being applied to small-capacity industrial requirements. The General Electric bipolar solid polymer cell also is moving toward commercialization, and can provide lower capital costs and improved efficiency in the near future. Table 14-3 lists the operating characteristics of the Lurgi, Teledyne, and General Electric electrolyzer cells. Because the cells require direct current, AC-to-DC rectification equipment will be necessary if DC power is not available. Such equipment is quite efficient, but the capital cost is high.

Table 14-3. OPERATING CHARACTERISTICS OF ELECTROLYZERS

Characteristic	Teledyne	Lurgi	General Electric
Size of system compared, MW equivalent of H_2	39.9	53.3	51.6
Million scf H_2/stream-day	10	13.44	13.0
DC electric input (max) (kW)	58,400	69,000	65,300
Specific cell efficiency (%)	68-70	77	82.2
AC to DC converter efficiency (%)	97	97	97
Auxiliary system efficiency loss (%)	2	NA[a]	1
Overall efficiency (%)	64-66	74.7	78.9
Operating pressure	100 psig	400 psia	Pressure vessel designed for operating pressure up to 3,000 psig
Cooling water	NA	184,940 gal./hr	Closed-cycle dry cooling tower
Feedwater (gal./1,000 scf)	6.36	6.36	6.36
Nitrogen per start-up (scf)	Yes	74,640	No
Caustic potash initial charge (lb)	NA	344,000	None
Labor	NA	2 men/shift	NA
Mode of operation	Fully automatic	Fully automatic	Fully automatic

[a]NA = not available.

Source: K. Darrow and others, "Commodity Hydrogen Off-Peak Electricity," *Proceedings, First World Hydrogen Energy Conference,* 1976.

Industrial electrolyzers range in size from 500 scf/day, consuming 3 kW of electricity, to more than 40 million scf/day, consuming 240 MW. One of the largest electrolyzers is the Cominco, Ltd. (British Columbia) 90 MW plant, which produces 13 million scf/day of hydrogen for use in ammonia synthesis.[2] In many parts of the world where inexpensive electric power is available, other large plants are operating, mainly to supply hydrogen to the ammonia and fertilizer industries. The world's first hydrogen-powered home was built recently in Provo, Utah, to demonstrate the practicality and simplicity of hydrogen conversion. The energy system produces hydrogen by electrolysis of water, using a solid polymer electrolyzer, and stores it in a metal hydride vessel. The system, which employs hot water storage tanks and a computer monitoring system, provides hydrogen for the home's gas appliances, boosts heat input to the heat pump used for space heating, and provides fuel for two vehicles.[16]

Hydrogen is attracting interest among power companies because it can be stored more easily than electricity. Niagara Mohawk Power Company of Syracuse, New York, plans to operate a 5 MW electrolysis/storage/fuel-cell demonstration system using the General Electric solid polymer electrolyzer. Electricity generated during low-demand periods will be used to electrolyze water to produce hydrogen. The hydrogen will be stored and used during peak electrical demand periods to generate electricity in a fuel cell or, during periods of peak gas demand, the hydrogen will be blended with natural gas. Utilities in Japan, England, and France are studying similar applications.

The most advanced electrolysis designs are encouraging, such as the General Electric solid polymer electrolyte, which is not a high temperature system and offers considerable advantages over conventional electrolyzers. Development efforts are focusing mainly on problems related to efficiency enhancement of advanced alkaline electrolyzers, development

of solid polymer electrolytes, solid electrolyte applications, and photolytical water splitting processes. However, the technical community is looking further to water splitting by other means, and because of its drawbacks, hydrogen production by electrolysis of water is not presently attracting industry.[1]

Thermal Splitting of Water

Direct thermal decomposition of water into hydrogen and oxygen requires temperatures of 4,000°C or greater; even then, however, the reaction is not complete and considerable additional energy is required to separate the product gases. Also, a reliable heat source for direct thermal splitting in quantity is not presently available. Therefore, other methods, such as thermochemical splitting of water, are being investigated.[17]

Thermochemical Splitting of Water

Much of the current hydrogen R&D effort is focused on hydrogen production by thermochemical water splitting. Thermochemical water splitting converts heat energy to chemical fuel without relying on electricity generation. Basically, the approach uses a sequence of reactions that when added together will give the net decomposition of water. The practical upper limit on temperature for any scheme would have to be about 900°C, if a nuclear heat source is used.

The United States, Japan, West Germany, Italy, and France are examining hundreds of possible thermochemical splitting schemes. One of the more prominent cycles is the DOE-sponsored General Atomics' prime cycle:

$$2HI_n \xrightarrow{425°C} nI_2 + H_2$$

$$2H_2O + SO_2 + nI_2 \xrightarrow{90°C} H_2SO_4 + 2HI_n$$

$$H_2SO_4 \xrightarrow{850°C} SO_2 + H_2O + \tfrac{1}{2}O_2$$

Other promising schemes are the Rohm and Haas sequence relying on iodine chemistry[18] and EURATOM's Mark IX thermochemical water decomposition process based on a ferrous chloride cycle.

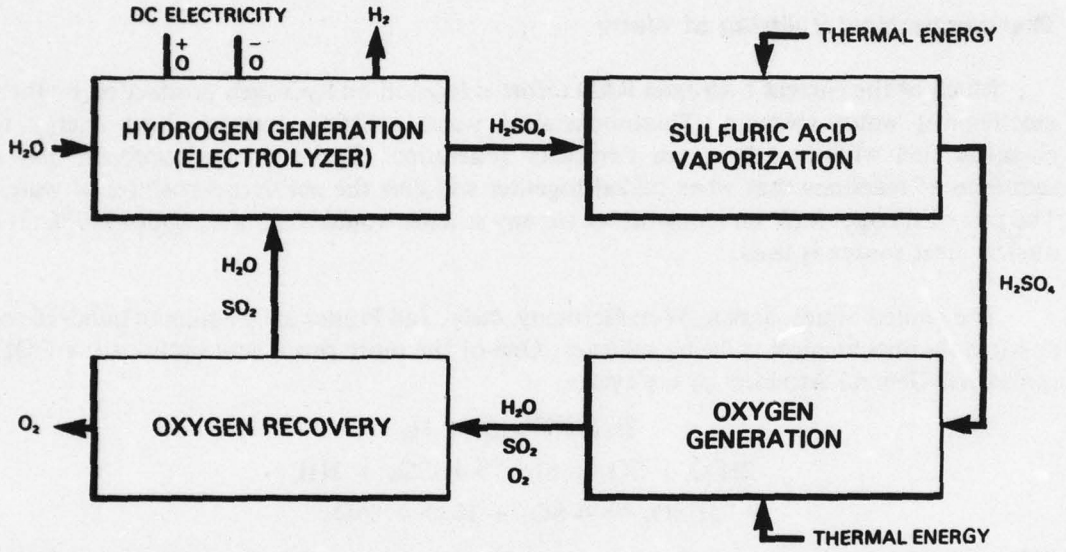
A potentially serious drawback to thermochemical production of hydrogen is that there will be some loss of reactants because the cycles are unlikely to be truly closed. At the quantities of hydrogen proposed, even the loss of a fraction of a percent per cycle would release large amounts of reactants, which could cause undesirable environmental effects. Furthermore, temperature requirements, corrosive properties of all the substances present, and cycle efficiencies must be considered in determining which schemes, if any, are economically feasible. The upper limit to the net efficiency of thermochemical decomposition cycles will probably be about 55 percent; however, this limit is greater than the projected net efficiency of 36 percent for hydrolysis.

Hybrid Cycles

Hybrid cycles are thermochemical cycles that include the direct input of energy through such means as an electrolysis step. An advantage of hybrid cycles is that the cycle avoids

some of the problems of handling very corrosive materials affecting the products and intermediates of most cycles.

Two prominent hybrid cycles sponsored by DOE are the Institute of Gas Technology (IGT) sequence (based on copper sulfate) and the Westinghouse sulfur cycle. Both cycles involve an electrochemical reaction as well as thermochemical decomposition. The IGT sequence has been operated on bench-scale with recycled materials; the Westinghouse cycle, shown in Figure 14-2, has been demonstrated in bench-scale apparatus, with a reported overall thermal efficiency of 45 percent. Other cycles are also being studied in the United States as well as abroad, particularly in West Germany, Canada, and Japan. Nevertheless, fully developed reaction schemes are not likely to be operated commercially for at least 15 to 20 years.[19]



Source: "Hydrogen Advocates Focus on Practical Goals," *Chemical and Engineering News, 56,* 14 August 1978.

Figure 14-2. WESTINGHOUSE HYBRID SULFUR CYCLE

HYDROGEN DISTRIBUTION

Hydrogen, in both gaseous and liquid forms, is transported from the source to the user by pipeline, truck, train, and barge. The methods and problems of handling and transporting hydrogen are similar to those for natural gas.

Pipeline

Transmission of moderate quantities of hydrogen gas by pipeline is an established industrial practice, but is normally carried out over short distances within the confines of the producers' facilities. Pressures usually are low, but NASA successfully operates pipelines at 6,000 psi. The only hydrogen pipeline in the United States for merchant hydrogen is

operated by Air Products and Chemicals, Inc., in the Houston, Texas, area. The pipeline supplies hydrogen and carbon monoxide to eight customers through about 96 km of underground pipes.[3] A comprehensive underground hydrogen pipeline network in the Ruhr Valley of Germany has a total length of 210 km and has been operating since 1938 with no significant problems. England is operating a hydrogen network consisting of 16 km of aboveground pipelines and an underground reservoir in three leached salt caverns. None of these networks is so long that in-line compressors are required to maintain transmission rates.

If hydrogen utilization is to achieve any significance as an energy alternative to the decreasing supply of natural gas, lower cost and more efficient transmission methods must be used. The preferred method is to transmit bulk gaseous hydrogen through a pipeline network similar to that presently used for natural gas. Preliminary evaluations indicate that this concept is feasible, however, the existing natural gas network will require extensive modification and expansion to adequately fill the needs of hydrogen transmission. The lower volumetric heating value of hydrogen, compared with natural gas, requires about three times the volumetric throughput (either with larger pipes or a faster flow rate), to achieve an equal energy output. Transmission of hydrogen gas, therefore, requires four times the compressor capacity and five times the horsepower.

A major problem in hydrogen transmission occurs when hydrogen embrittlement of carbon steels causes metal fatigue, which can result in catastrophic failure of pipelines. This was evidenced when the 2.5 cm diameter, 6.4 km long Los Alamos pipeline (operating at 2,000 psi) failed after 3½ years of use.[7,9] Since hydrogen must be transmitted at high pressures, problems must be resolved to make existing pipelines satisfactory for hydrogen transmission. DOE currently is sponsoring theoretical and experimental studies to determine the most suitable materials and designs for constructing hydrogen storage, transmission, and distribution systems.

Pipeline transmission of liquid hydrogen presents greater problems than that of liquid natural gas because the temperature at which hydrogen enters the liquid phase is $-253\,^{\circ}C$; thermal insulation and in-line refrigeration plants would greatly increase the capital costs of the pipeline. Therefore, pipeline transmission of liquid hydrogen, which has been limited to short lines at production plants and to somewhat longer lines at space program test and launch facilities, may be desired only if the end-use form requires liquid hydrogen.[20]

The expense of pipelining oxygen (a by-product of the electrolysis and thermochemical production of hydrogen) is prohibitive over distances greater than 30 miles. If liquid hydrogen is the chosen method for transporting energy, the recovery of the hydrogen liquefaction energy can make it possible to separate stoichiometric amounts of oxygen from air on-site with little additional energy.[21]

The possibility of pipeline transmission of subcooled liquid hydrogen as a slush (solid/liquid) mixture has been suggested. The advantages of this approach are an increased density of 15 to 20 percent over cryogenic hydrogen and the very significant additional heat sink capability, minimizing the refrigeration required along the pipeline.

Truck, Train, and Barge

Transportation of small volumes of gaseous hydrogen in high pressure containers is common, but this form of transmission is impractical for large volumes.[22] The only method currently used in the United States to transport large quantities of hydrogen over long distances is by shipping liquid hydrogen in evacuated, double-wall insulated containers mounted on trailer trucks, railway cars, or barges.[6] However, insulation problems and boil-off losses are disadvantages of this method of long-distance transmission of hydrogen.

The Chicago Bridge and Iron Company has built hydrogen transportation barges for NASA with tank capacities of 240,000 gal. The tanks consist of concentric cylinders; the 58 cm space between the cylinders is evacuated and contains perlite. The boil-off losses from these tanks is about 0.25 percent/day.[22]

HYDROGEN STORAGE

Compared with the total amount of hydrogen produced and consumed in the world, an insignificant amount is stored for any length of time. Most hydrogen is consumed by the producers, who convert the hydrogen into an end product in their own facilities. However, hydrogen storage on a large scale is necessary to allow production and transmission facilities to operate at a fairly even rate while customers are supplied at a rate that fluctuates widely on daily, weekly, and seasonal cycles. Storage close to the load center is desirable to reduce demands on the transmission system. Hydrogen can be stored both as a gas and as a liquid, with the type of storage depending on end use.

Gaseous Hydrogen

Because the heating value of hydrogen is about a third that of natural gas on a volume basis, larger storage fields and tanks are required for hydrogen than are required for natural gas. Storage of hydrogen gas in depleted natural gas fields appears to be feasible, particularly if such fields are near the point of use.

Gaseous hydrogen usually is stored in banks of portable, high-pressure containers or seamless tanks at pressures as high as 6,000 psig. Larger quantities of gaseous hydrogen are stored in welded, laminated-wall, pressure vessels at pressures as high as 15,000 psig. The few welded, low-carbon steel pressure vessels still in service are being derated to preclude hydrogen embrittlement and ensure compatibility with hydrogen. These vessels have typical operating pressures less than 3,000 psig and will probably be removed from service at the earliest opportunity.[6]

Liquid Hydrogen

Storage of liquid hydrogen in evacuated, double-wall insulated containers provides an acceptable loss rate, especially when integrated with a device that periodically demands enough hydrogen to use the boil-off gas that normally would be flared. Experience shows that the larger the storage container the smaller the percentage of stored hydrogen that is lost

by boil-off. If the construction costs of the container could be lowered, some loss in storage efficiency would be conditionally acceptable.

Special insulating materials for aboveground storage vessels have been developed but the cost is high. The U.S. space program uses 500,000 gal. storage tanks insulated with perlite contained in the evacuated 30 cm thick space between the tank walls. These tanks have a boil-off rate of about 0.03 percent/day. Railroad cars with a capacity of 28,000 gal. have a boil-off rate of 0.3 percent and small mobile storage units lose hydrogen at a rate of 1 to 2 percent/day.[7,9] The high cost of small liquid hydrogen storage tanks is an obstacle to their use. Cryogenic inground storage systems with frozen, moisture-saturated soil as the actual tank wall and insulation do not presently appear to be applicable for storing hydrogen.[9]

Metal Hydrides

The use of metal hydrides is proposed for hydrogen or energy storage because of the extremely high volumetric density of hydrogen in metal hydrides. As shown in Table 14-4, more hydrogen can be packed in a metal hydride than in the same volume of liquid hydrogen.[23]

Table 14-4. COMPARISON OF HYDROGEN STORAGE MEDIA

Medium	Hydrogen Content (Weight percent)	Hydrogen Storage Capacity (g/ml)	Energy Density[b]	
			(cal/g)	(cal/ml)
MgH_2[a]	7.0	0.101	2,373	3,423
Mg_2NiH_4	3.16	0.081	1,071	2,745
VH_2	2.07	—	701	—
$FeTiH_{1.95}$	1.75	0.096	593	3,245
$LaNi_5H_{7.0}$	1.37	0.089	464	3,051
Liquid H_2	100	0.07	33,900	2,373
Gaseous H_2 (100 atm pressure)	100	0.007	33,900	244
n-Octane	—	—	11,400	8,020

[a]Starting alloy: 94 percent Mg and 6 percent Ni.

[b]Refers to heat of combustion of hydrogen only.

Source: F. E. Lynch and E. Snape, "The Role of Metal Hydrides in Hydrogen Storage and Utilization," *Hydrogen Energy System,* Proceedings of the Second World Hydrogen Energy Conference, Zurich, Switzerland, 21-24 August 1978 (New York: Pergamon Press, 1978), Vol. 3.

The formation of metal hydrides is exothermic. Consequently, heat is required to release hydrogen from the hydride. Typically, for each pound of hydrogen released, 15,000 Btu must be supplied to dissociate the hydrogen. This is 29 percent of the heating value of the hydrogen released. In addition to the thermal penalty paid to release the hydrogen, the storage medium is heavy and costly and is not considered economically feasible. Use of lightweight metal hydrides could significantly alter the economics, however. Many problems, such as hydride packing, swelling, disproportionation, and poisoning, remain to be solved before metal hydride systems are considered commercially feasible for hydrogen storage.

Representatives of the automobile industry indicate that storage is the most difficult problem to overcome in implementing the use of metal hydride systems.[18] In Germany, Daimler-Benz has developed a 60 HP minibus with a 4-cylinder hydrogen-powered engine. Hydrogen is carried in a 65 liter tank containing 200 kg of an iron-titanium hydride, which can absorb a charge equivalent to 50,000 standard liters of hydrogen, enough for 108 to 113 km of stop-and-go city driving. In the United States, the Billings Energy Research Corporation, Provo, Utah, is using an iron-titanium hydride in a minibus that will run a 1 year trial in a 23 km loop between Provo and Orem, Utah. Billings also is developing a fleet of cars for the hydrogen plant it is designing for Forest City, Iowa, and is modifying an AMC jeep for a 6 month test by the postal service in Washington, D.C.[18] The vehicle research laboratory has a hydrogen-powered bus in service in Riverside, California.

ENVIRONMENTAL AND SAFETY ISSUES

Environmental Aspects

Hydrogen is almost an ideal fuel from an environmental viewpoint, as it produces significantly fewer pollutants than fossil or nuclear fuels. When hydrogen is burned with air, only water and some nitrogen oxides are formed. Since no carbon is present to form carbon oxides or hydrocarbons, nitrogen oxides are the only real pollutants produced. These can be controlled and suppressed by the proper choice of combustion conditions. The water is considered a pollutant only if the amount produced is large enough to require removal by dehumidification or some other means.

The amount of nitrogen oxides produced by combusting hydrogen probably is about the same as that produced by burning gasoline, but some studies indicate the amount from hydrogen is considerably less. Also, hydrogen burns at lower temperatures than natural gas in space heaters and stoves, resulting in practically no nitrogen oxide formation and eliminating the need for vents on such units.

Adverse environmental effects of using hydrogen fuel on a large scale would result largely from use of coal gasification and nuclear plants to produce the hydrogen. However, since it is considerably easier to remove pollutants from effluents from a few large stationary sources than from many small mobile sources, use of hydrogen as a principal energy source would result in a cleaner environment.

Because hydrogen can be transmitted through underground pipelines when materials problems are resolved, piping hydrogen to electrical substations for conversion to electricity would eliminate unsightly overhead lines required for transmitting electricity to substations.

Safety Hazards

The main safety hazards associated with hydrogen use are fire and explosion, making hydrogen dangerous to handle and transport. Hydrogen's flammability limits range from 4.1 to 74.8 percent, compared with 5.3 to 15 percent for methane. Hydrogen's ignition

energy is so low that even a static electric discharge from a polyester garment will ignite it. NASA has found that fire occurs 62 percent of the time when hydrogen is spilled or released to the atmosphere and 100 percent of the time when released in enclosures. Spills to the atmosphere do not seem to create an explosion hazard but, in many cases, spills in an enclosure result in an explosion. Studies of the dangers of liquid hydrogen spills indicate that ignition can occur only in the cloud formed within 30 m of the spill, but the data are not conclusive.

In motor vehicles, collisions represent the greatest hazard of hydrogen use because sparks can ignite the hydrogen; unlike gasoline, however, if hydrogen does not ignite immediately, it rises and dissipates. Use of metal hydrides creates additional problems because hydrides emit hydrogen when heated and the remaining powdered metals (for example, magnesium) can burn.

Because hydrogen is odorless and burns invisibly, an odorant and illuminant must be added to hydrogen if it is to be distributed through a pipeline system and used as a residential fuel.

Piping, valves, controls, and equipment for hydrogen service generally require standards for materials, design, quality control, and maintenance that are much more stringent than those for other fuels because of hydrogen's low viscosity and density and its high diffusivity. Widespread deployment of hydrogen service utilities will require high performance standards to avoid potential hazards.

HYDROGEN ECONOMICS

The price of merchant hydrogen depends greatly on the purity required; in 1974, high-purity hydrogen cost $7.60/thousand scf, but low-purity hydrogen was available at $0.98/thousand scf. Captive hydrogen was only about $0.40/thousand scf (see Table 14-5).

The cost of hydrogen production varies with the process and the size of the plant. The cost of refinery hydrogen

Table 14-5. TIME-PRICE RELATIONSHIP FOR HYDROGEN

Year	Average Annual Price (Cents/1,000 scf)				
	Captive		Merchant[a]		
	Actual	Constant 1973	High Purity	Lower Purity	Total Merchant
1954	31.00	53.36	—	—	—
1955	30.00	50.93	—	—	—
1956	29.20	47.95	—	—	—
1957	28.50	45.10	—	—	—
1958	28.00	43.21	—	—	—
1959	27.60	41.88	—	—	—
1960	27.00	40.36	—	—	—
1961	26.50	39.08	125	35	98
1962	26.30	38.34	162	27	127
1963	26.00	37.41	157	25	157
1964	25.70	36.45	185	30	152
1965	25.40	35.38	164	32	148
1966	25.20	34.15	151	30	140
1967	25.10	32.93	150	35	141
1968	25.00	31.52	145	32	137
1969	24.50	29.48	162	34	150
1970	25.10	28.65	181	48	169
1971	25.85	28.22	355[b]	121[c]	181
1972	26.24	27.71	407[b]	83[c]	169
1973	30.00	30.00	492[b]	80[c]	202
1974	40.00[d]	36.27[d]	760[b]	98[c]	282
1975	60.00[d]	49.96	NA[e]	NA	NA

[a]All merchant hydrogen data is from the U.S. Department of Commerce, Bureau of the Census, Current Industrial Reports, "Industrial Gases."

[b]Produced and shipped for cylinder and bulk delivery shipment and liquid produced for conversion of gas.

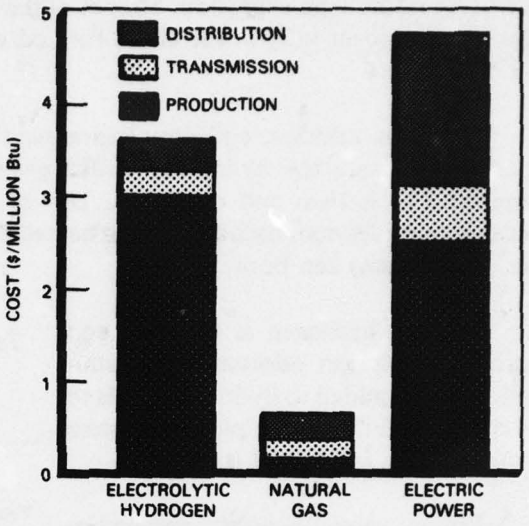
[c]Produced and shipped for pipeline shipment and liquid produced for government use.

[d]Estimated.

[e]NA = not available.

Source: Daniel C. Adkins and Robert J. Jaske, "Hydrogen," *Mineral Facts and Problems* (Washington, D.C.: Bureau of Mines, U.S. Department of the Interior, 1975).

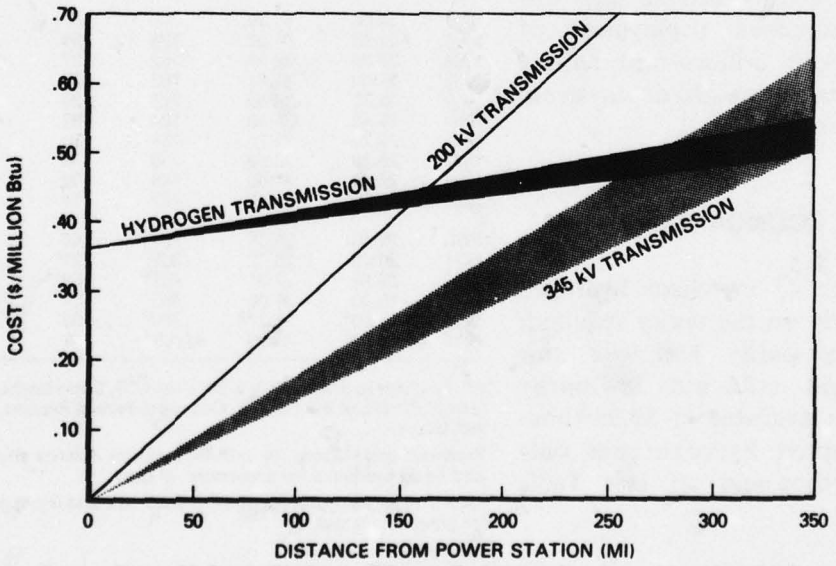
from steam reforming of petroleum stocks is expected to rise from about $6.00/thousand scf/day in 1980 to about $7.50/thousand scf/day in 2000. The corresponding costs of hydrogen from coal are estimated to be $8.00 and $10.00.[7] Recent studies indicate that the cost of producing hydrogen using the Lurgi coal gasification process is expected to be $5.10 to $6.00/million Btu ($1.66 to $1.95/thousand scf), depending on the plant size and the number of gasifiers used. The cost of producing 97.4 percent pure hydrogen using the Koppers-Totzek process is estimated to be $5.50 to $7.00/million Btu.[7-9] The Forest City, Iowa, experimental plant will produce hydrogen for an estimated $2.95/thousand scf.



Source: Robert M. Reed, "Hydrogen," *Energy Technology Handbook* (New York: McGraw-Hill Book Company, 1976).

Figure 14-3. COST COMPARISON OF THREE ENERGY SOURCES

An IGT study of the benefits of pipeline transmission of gaseous hydrogen fuel compared the major cost segments of electrolytic hydrogen, natural gas, and electric power, as shown in Figure 14-3. This figure indicates hydrogen to be a cost-attractive alternative to natural gas when the natural gas resource is exhausted. Figure 14-4 compares the cost of distributing hydrogen by pipeline over moderate distances to that of moderate voltage electrical transmission



Source: Robert M. Reed, "Hydrogen," *Energy Technology Handbook* (New York: McGraw-Hill Book Company, 1977).

Figure 14-4. COMPARISON OF ENERGY TRANSMISSION COSTS

lines.[4] The cost of transporting hydrogen by pipeline is estimated to be two to three times that of transporting natural gas, because of the special problems noted. High-purity, special purpose hydrogen is commonly trucked or railed in liquid form in Dewar containers of up to tank-car size, but the cost is high because of special equipment needs and the loss of hydrogen from boil-off.

Hydrogen energy systems will not offer much of a challenge to electricity until present supplies of fossil fuels dwindle to the point where energy is available only at three or four times the present cost. Although strong environmental reasons exist for using hydrogen fuel immediately, economics will dictate the eventual date and method.[1]

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15. FUEL CELLS

A fuel cell is a device in which the chemical energy of a fuel is converted directly into electrical power. As illustrated in Figure 15-1, the reactants (fuel and oxidant) are fed continuously from the outside of the cell, and the products of the reaction are removed continuously. The fuel cell is capable of very high efficiencies because it is not limited to the efficiency of the Carnot cycle (as are heat engines).

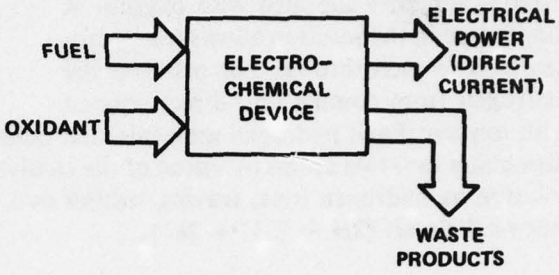


Figure 15-1. BASIC FUEL CELL

The first hints of a fuel cell concept occurred in the early 1800s when Sir Humphrey Davy reported on the construction of simple galvanic combinations.[1] However, the first discovery of the fuel cell is usually credited to Sir William Grove in the late 1830s.[2,3] In his experiments, Grove demonstrated that the electrolysis of water was a reversible process and that hydrogen and oxygen could be recombined in an electrochemical cell to produce electrical power.

The first serious attempt to produce a practical fuel cell device was made by Mond and Langer in the 1880s.[4] Their aim was to use a cheaper fuel than hydrogen and to replace the platinum electrodes used by Grove with a much cheaper metal, such as nickel. It was during these experiments that Mond and Langer discovered the carbonyl process for refining nickel; this diverted their attention from fuel cells, but led to the founding of a large nickel industry. In the early 1900s, Bauer worked on high-temperature fuel cells with the prime objective of obtaining electricity directly from coal.[5] However, this objective was too ambitious for the time.

Among the most important work in the development of fuel cells was that of Francis T. Bacon, of Great Britain, in the 1930s. His original objective was to develop a practical energy storage device. Although the work on his hydrogen-oxygen fuel cell was interrupted by World War II, he returned to the task and, in 1959, demonstrated a 6 kW unit.[6] It was the Bacon cell that later was developed further for use in Project Apollo by Pratt and Whitney Aircraft, now the Power Systems Division of United Technologies Corporation (UTC).

Much of the current fuel cell research and development is being directed toward reducing costs and making fuel cells more practical. The focus of many of these programs is either to achieve high power densities for application in transportation (cars, trains, ships, buses, and trucks) or to achieve high energy efficiencies with available fuels for use in electrical power generation.

BASIC HYDROGEN-OXYGEN FUEL CELL

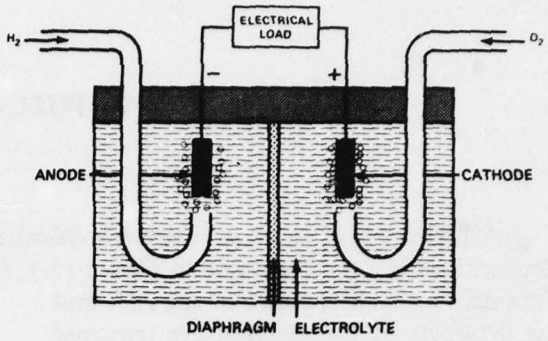
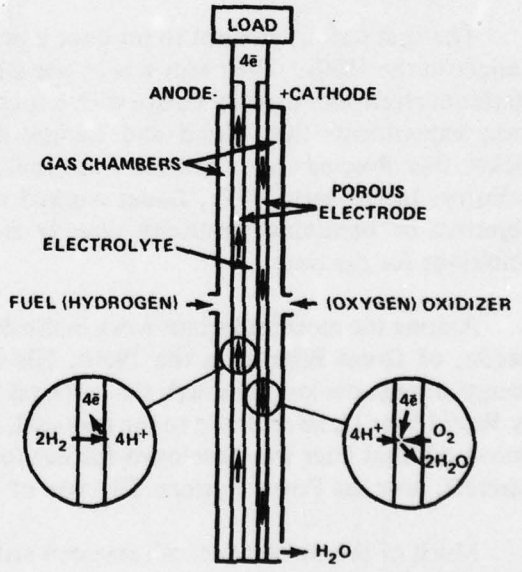


Figure 15-2. SIMPLE HYDROGEN-OXYGEN FUEL CELL

The principle of hydrogen-oxygen fuel cell operation is shown in Figure 15-2. Two platinum foil electrodes are immersed in a conductive acid electrolyte. One electrode is supplied with hydrogen, bubbled around it through the solution, and the other electrode is similarly supplied with oxygen. A diaphragm in the solution allows the hydrogen ions to pass through but prevents the hydrogen from coming into direct contact with oxygen. Each hydrogen molecule that contacts the negative electrode (anode) surface dissociates into two atoms by virtue of the catalytic properties of the surface. These enter the solution as hydrogen ions, leaving behind two electrons which pass through the external electrical circuit ($2H \rightarrow 2H^+ + 2e^-$).

At the cathode, free hydrogen ions from the electrolyte combine with oxygen and gain two electrons to form water ($\frac{1}{2}O_2 + 2H^+ + 2e^- \rightarrow H_2O$). A "cold" electrochemical reaction occurs at two separated reaction sites to replace the normal single combustion process that occurs in a hydrogen-oxygen "flame."

The simple hydrogen-oxygen fuel cell is not of practical value because it does not provide a way to remove the water that is generated as a waste product. A fuel cell that does allow the water to be removed is shown in Figure 15-3. This fuel cell incorporates porous electrodes that can be "wet" by the electrolyte. The gas pressures must be selected carefully to avoid flooding or drying the electrode pores, either of which would impede the reaction rate and limit the current flow.



Source: General Electric Company, Publication GEA-7978, 1964.

Figure 15-3. FUEL CELL WITH POROUS ELECTRODES

FUEL CELL DESIGNS

Many different and varied designs are possible with fuel cells. The selection is usually dictated by size, weight, and fuel requirements, or environmental and economic considerations. The characteristics of electrolytes for large-scale fuel cells are shown in Table 15-1. The more common types of fuel cells are described below.

Table 15-1. CHARACTERISTICS OF ELECTROLYTES FOR LARGE-SCALE FUEL CELLS

Electrolyte	Operating Temperature Range (°C)	Fuel/Oxidant Requirements	Remarks
Phosphoric acid	150-200	The percentage of carbon monoxide in the fuel must be kept low because it might interfere with the cell's performance.	First-generation large-scale power plants use this electrolyte.
Alkaline	25-125[a]	The fuel or oxidant cannot contain carbonaceous impurities which react with the electrolyte, affecting performance negatively.	
Molten carbonate	600-700	Fuel streams with large quantities of carbon dioxide and carbon monoxide are acceptable because those substances are used in the cell's electrochemical reactions.	The molten carbonate fuel cell is about 5 years behind the phosphoric acid cell in technological development.

[a]Without pressurization.

Source: Electric Power Research Institute, "Clean Power for the Cities," *EPRI Journal*, Vol. 3, No. 9, November 1978.

Direct Type, Alkaline Electrolyte

The basic structure of a direct alkaline electrolyte fuel cell is shown in Figure 15-4. The electrodes are made of porous conductors. A 20 to 40 percent solution of potassium hydroxide is a typical electrolyte. The electrochemical reactions with hydrogen as a fuel are:

At the cathode:

$$O_2 + 2H_2O + 4e^- \rightarrow 4\,(OH)^-$$

At the anode:

$$2H_2 + 4\,(OH)^- \rightarrow 4H_2O + 4e^-$$

Overall reaction:

$$2H_2 + O_2 \rightarrow 2H_2O$$

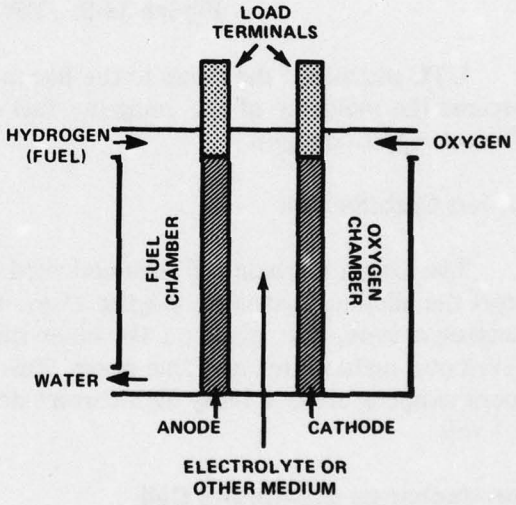
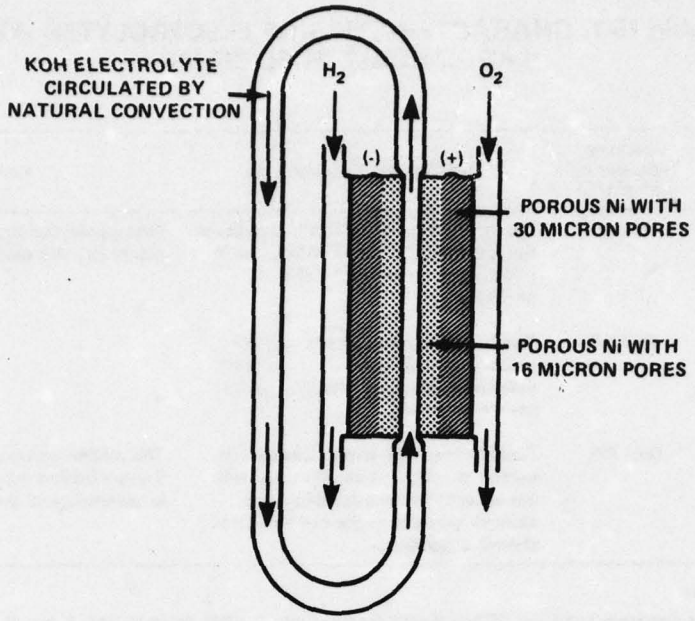


Figure 15-4. DIRECT TYPE FUEL CELL

Bacon Cell

The Bacon cell, invented by F. T. Bacon using an alkaline electrolyte, was among the first of the high-performance cells. It operates at about 200°C to support the reaction and at 400 to 1,000 psi to prevent the electrolyte from boiling. Although this fuel cell has the disadvantage of requiring a pressurization system, it provides high current densities of about 750 amperes/ft² of electrode at 0.7 volt. Figure 15-5 illustrates one Bacon cell design used by the Patterson Moos Division of the Leesona Corporation. The electrodes are made of sintered nickel with finer pores near the electrolyte.



Source: S. S. L. Chang, *Energy Conversion* (Englewood Cliffs, NJ: Prentice-Hall, Inc., 1963).

Figure 15-5. TYPICAL BACON CELL

UTC purchased the rights to the Bacon cell in 1960. After extensive redesign, this cell became the mainstay of the company fuel cell designs (one of which was the successful Project Apollo design).

Union Carbide Cell

The Union Carbide cell uses activated carbon electrodes treated with a substance to repel the alkaline electrolyte (Figure 15-6). The reactions, which are of the direct alkaline electrolyte type, take place on the outer surfaces of the electrodes, which have a highly developed surface area and fine pores. This cell design has the advantage of operating at room temperature at a fairly high current density of about 100 amperes/ft² of electrode at 0.7 volt.

Ion-Exchange Membrane Cell

The ion-exchange membrane fuel cell, illustrated in Figure 15-7, was developed by General Electric Company. The ion-exchange membrane performs the function of an acid electrolyte but in a quasisolid state. Hydrogen ions can move from one side of the membrane to the other, but other types of ions and neutral atoms cannot. Each side of the membrane is coated with a layer of platinum or palladium, which serves as an electrode as well as an electrocatalyst. These cells have current densities of about 30 to 50 amperes/ft² at 0.7 volt.

High-Temperature Cell

Hydrocarbon fuels usually can be converted into a mixture of hydrogen and carbon

monoxide in a reversible process. High-temperature fuel cells that use these two fuels have been developed. Carbon monoxide does not react as readily as hydrogen and also causes problems with many of the acid and alkaline electrolytes. Thus, carbonates are used as a weak alkali at high temperatures and the electrode reactions are:

At the cathode:

$$O_2 + 2CO_2 + 4e^- \rightarrow 2CO_3^{--}$$

At the anode:

$$H_2 + CO_3^{--} \rightarrow H_2O + CO_2 + 2e^-$$

$$CO + CO_3^{--} \rightarrow 2CO_2 + 2e^-$$

Typical current densities range from 20 to 100 amperes/ft² at 0.7 volt.

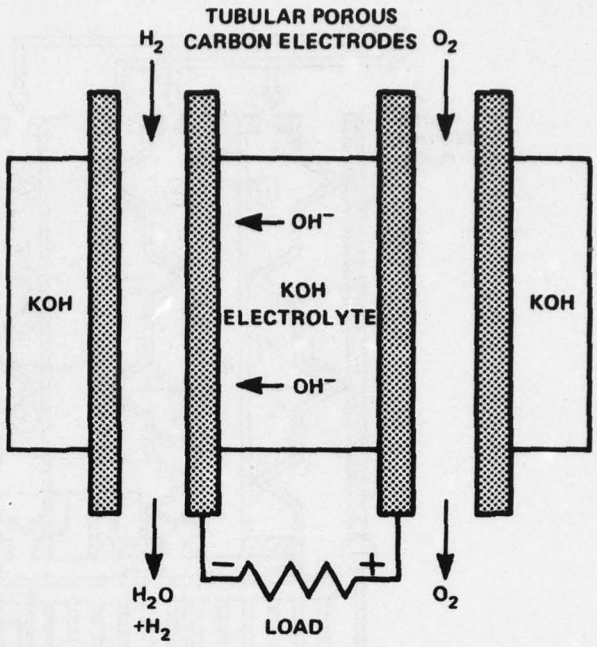


Figure 15-6. UNION CARBIDE FUEL CELL

Redox Cell

The Redox cell (Figure 15-8) is different from the normal fuel cell because the fuel and oxidant are used to regenerate two electrolytic fluids instead of reacting at the electrodes directly. The cell is divided by a diaphragm, which allows free passage of the hydrogen ions. Typical Redox cells are being developed by:

- General Electric Company, using hydrogen fuel and oxygen oxidant.

  Anode reaction:

  $$2Ti^{+++} + 2H_2O \rightarrow 2TiO^{++} + 4H^+ + 2e^-$$

  Anode regeneration:

  $$2TiO^{++} + 2H^+ + H_2 \rightarrow 2Ti^{+++} + 2H_2O$$

  Overall reaction on anode side:

  $$H_2 \rightarrow 2H^+ + 2e^-$$

  Cathode reaction:

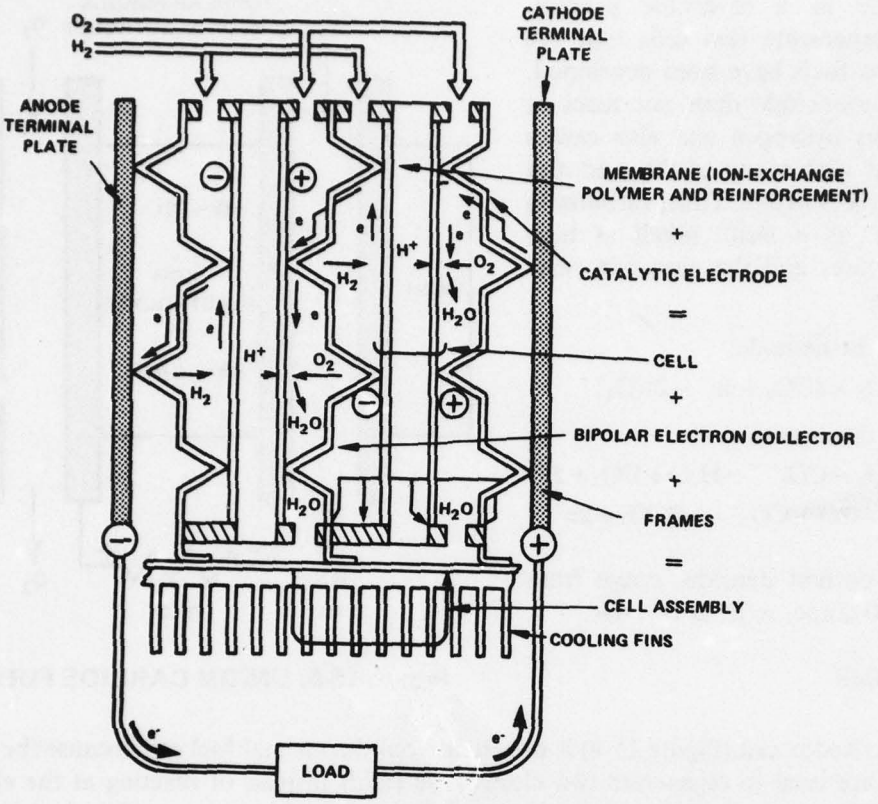
  $$Br_2 + 2e^- \rightarrow 2Br^-$$

  Cathode regeneration:

  $$2H^+ + 2Br^- + \tfrac{1}{2}O_2 \rightarrow Br_2 + H_2O$$

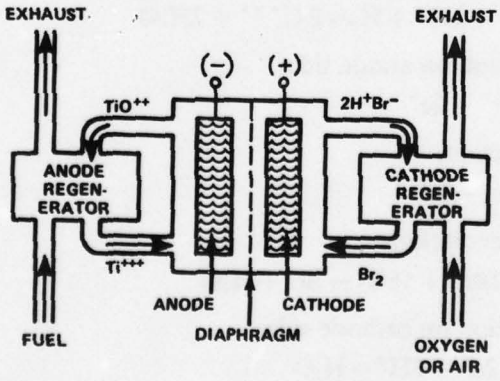
  Overall reaction on cathode side:

  $$\tfrac{1}{2}O_2 + 2e^- + 2H^+ \rightarrow H_2O$$



Source: G. A. Phillips, "Status of the Ion-Exchange Membrane Fuel Cell," *Electrical Engineering,* Vol. 81, No. 3, March 1962.

Figure 15-7. ION-EXCHANGE MEMBRANE FUEL CELL



Source: S. S. L. Chang, *Energy Conversion* (Englewood Cliffs, NJ: Prentice-Hall, Inc., 1963).

Figure 15-8. REDOX CELL

- King's College, London, with coal powder fuel and air oxidant. (This is a low current density cell of 10 amperes/ft² at 0.62 volt.)

  Anode reaction:

  $$2Sn^{++} \rightarrow 2Sn^{++++} + 4e^-$$

  Anode regeneration:

  $$2Sn^{++++} + 2H_2O + C \rightarrow CO_2 + 2Sn^{++} + 4H^{++}$$

  Overall reaction on anode side:

  $$C + 2H_2O \rightarrow CO_2 + 4H^+ + 4e^-$$

  Cathode reaction:

  $$2Br_2 + 4e^- \rightarrow 4Br^-$$

  Cathode regeneration:

  $$4Br^- + 4H^+ + O_2 \rightarrow 2Br_2 + 2H_2O$$

  Overall reaction on cathode side:

  $$4H^+ + O_2 + 4e^- \rightarrow 2H_2O$$

Hydrazine Fuel Cells

Hydrazine fuel cells are used where high energy density with respect to volume and weight is required. (These conditions often exist in military applications.) Hydrazine, noted for its remarkable electrochemical activity, does not require the use of noble metals as anode catalysts. Further, its reaction products do not contaminate the electrolyte. Unfortunately, hydrazine is very expensive. A typical electrochemical reaction in an alkaline solution is:

Anode reaction:

$$N_2H_{4_{aq}} + 4OH^- \rightarrow N_2 + 4H_2O + 4e^-$$

Cathode reaction:

$$O_2 + 2H_2O + 4e^- \rightarrow 4OH^-$$

Overall reaction:

$$N_2H_{4_{aq}} + O_2 \rightarrow N_2 + 2H_2O$$

FUEL CELL EFFICIENCY

The potential for high energy conversion efficiency is one of the strong selling points for fuel cells. Many energy systems using fuel cells require modification of the fuel to a form that is compatible with the fuel cell. For example, a system using natural gas normally would require a "reformer," and a system using coal would require that it be gasified, liquefied, or finely ground. The electrical power leaves the fuel cell as a direct current (DC), but this would have to be converted to mechanical power to drive a vehicle or be converted to alternating current (AC) for a utility. Thus, the real efficiencies that must be considered are the overall efficiencies of converting the fuel available to output power in the form required—

that is, overall efficiency = (efficiency of the input interface device) × (ideal efficiency) × (voltage efficiency) × (reaction efficiency) × (efficiency of the output interface device). There are at least two configurations that would require a modification of the simple product efficiency calculation. These are shown in Figures 15-9 and 15-10. In the first of these, waste heat or waste fuel from the cell is used by the input interface device; in the second, waste heat or fuel is converted to useful power by a heat engine.

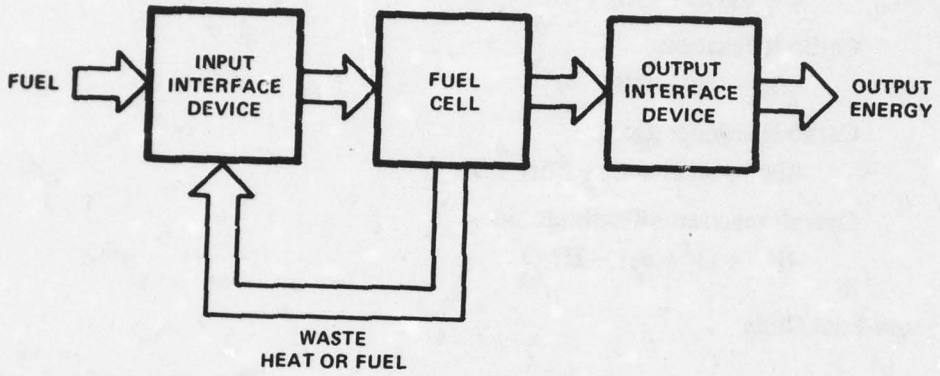


Figure 15-9. FUEL CELL EFFICIENCY IMPROVEMENT—CONFIGURATION 1

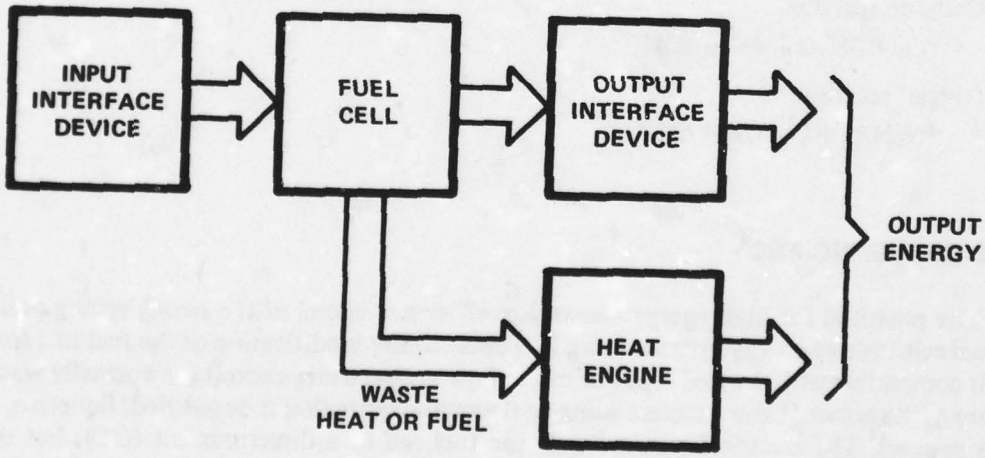


Figure 15-10. FUEL CELL EFFICIENCY IMPROVEMENT—CONFIGURATION II

Input Interface Device Efficiency

Typical input interface devices include reformers and coal gasifiers. Efficiencies from about 60 percent to nearly 100 percent are attainable for gasification processes. A gas or liquid fuel reformer would normally have efficiencies of 80 to 90 percent.[7]

Ideal Efficiency

The ideal efficiency is defined as the ratio of the maximum amount of electrochemical energy that can be obtained from a chemical reaction to the heat energy of the reaction. Representative ideal efficiencies for several chemical reactions are shown in Table 15-2. (Note that the efficiencies are for 25°C. These efficiencies change with temperature.)

Voltage Efficiency

Voltage efficiency at a given load is defined as the terminal voltage at a given load divided by the ideal no-load voltage. The voltage efficiency of fuel cells is a function of current flow. It includes all of the irreversible losses occurring in the cell under a specific load condition. These losses include cell resistance and voltage drops in electrode potential (for example, due to a side reaction). Voltage efficiency strongly depends on the electrode materials, electrolyte conductance, and cell geometry. The value of voltage efficiency can vary from nearly 100 percent at low load factors to nearly 0 percent at very high loads, but typically ranges from 50 to 90 percent.

Reaction Efficiency

Not all of the fuel and oxidizer supplied to a fuel cell is used to generate electricity.

Table 15-2. IDEAL EFFICIENCY VALUES

REACTANT Half-Cell Reaction Complete-Cell Reaction	Ideal Efficiency[a] (Percent)
HYDRAZINE (aq)	
$N_2H_4\ (aq) + 4\ OH^- \rightleftharpoons N_2 + 4\ H_2O + 4\ e^-$	
$N_2H_4\ (aq) + O_2 \rightleftharpoons N_2 + 2\ H_2O$	99.4
ETHANOL (aq)	
$C_2H_5OH\ (aq) + 3\ H_2O \rightleftharpoons 2\ CO_2 + 12\ H^+ + 12\ e^-$	
$C_2H_5OH\ (aq) + 3\ O_2 \rightleftharpoons 2\ CO_2 + 3\ H_2O$	97.5
BENZENE	
$C_6H_6 + 12\ H_2O \rightleftharpoons 6\ CO_2 + 30\ H^+ + 30\ e^-$	
$C_6H_6 + 7\frac{1}{2}\ O_2 \rightleftharpoons 6\ CO_2 + 3\ H_2O$	97.2
METHANOL (aq)	
$CH_3OH\ (aq) + H_2O \rightleftharpoons CO_2 + 6\ H^+ + 6\ e^-$	
$CH_3OH\ (aq) + 1\frac{1}{2}\ O_2 \rightleftharpoons CO_2 + 2\ H_2O$	97.1
PROPYLENE	
$C_3H_6 + 6\ H_2O \rightleftharpoons 3\ CO_2 + 18\ H^+ + 18\ e^-$	
$C_3H_6 + 4\frac{1}{2}\ O_2 \rightleftharpoons 3\ CO_2 + 3\ H_2O$	95.1
ACETYLENE	
$C_2H_2 + 4\ H_2O \rightleftharpoons 2\ CO_2 + 10\ H^+ + 10\ e^-$	
$C_2H_2 + 2\frac{1}{2}\ O_2 \rightleftharpoons 2\ CO_2 + H_2O$	95.0
PROPANE	
$C_3H_8 + 6\ H_2O \rightleftharpoons 3\ CO_2 + 20\ H^+ + 20\ e^-$	
$C_3H_8 + 5\ O_2 \rightleftharpoons 3\ CO_2 + 4\ H_2O$	95.0
ETHYLENE	
$C_2H_4 + 4\ H_2O \rightleftharpoons 2\ CO_2 + 12\ H^+ + 12\ e^-$	
$C_2H_4 + 3\ O_2 \rightleftharpoons 2\ CO_2 + 2\ H_2O$	94.3
ETHANE	
$C_2H_6 + 4\ H_2O \rightleftharpoons 2\ CO_2 + 14\ H^+ + 14\ e^-$	
$C_2H_6 + 3\frac{1}{2}\ O_2 \rightleftharpoons 2\ CO_2 + 3\ H_2O$	94.1
METHANE	
$CH_4 + 2\ H_2O \rightleftharpoons CO_2 + 8\ H^+ + 8\ e^-$	
$CH_4 + 2\ O_2 \rightleftharpoons CO_2 + 2\ H_2O$	91.9
CARBON MONOXIDE	
$CO + H_2O \rightleftharpoons CO_2 + 2\ H^+ + 2\ e^-$	
$CO + \frac{1}{2}\ O_2 \rightleftharpoons CO_2$	90.9
HYDROGEN	
$H_2 \rightleftharpoons 2\ H^+ + 2\ e^-$	
$H_2 + \frac{1}{2}\ O_2 \rightleftharpoons H_2O$	83.0

[a]Standard-state free energy of reaction at 25°C divided by standard-state heat of reaction at 25°C.

Source: Carl Berger, ed., *Handbook of Fuel Cell Technology* (Englewood Cliffs, NJ: Prentice-Hall, Inc., 1968).

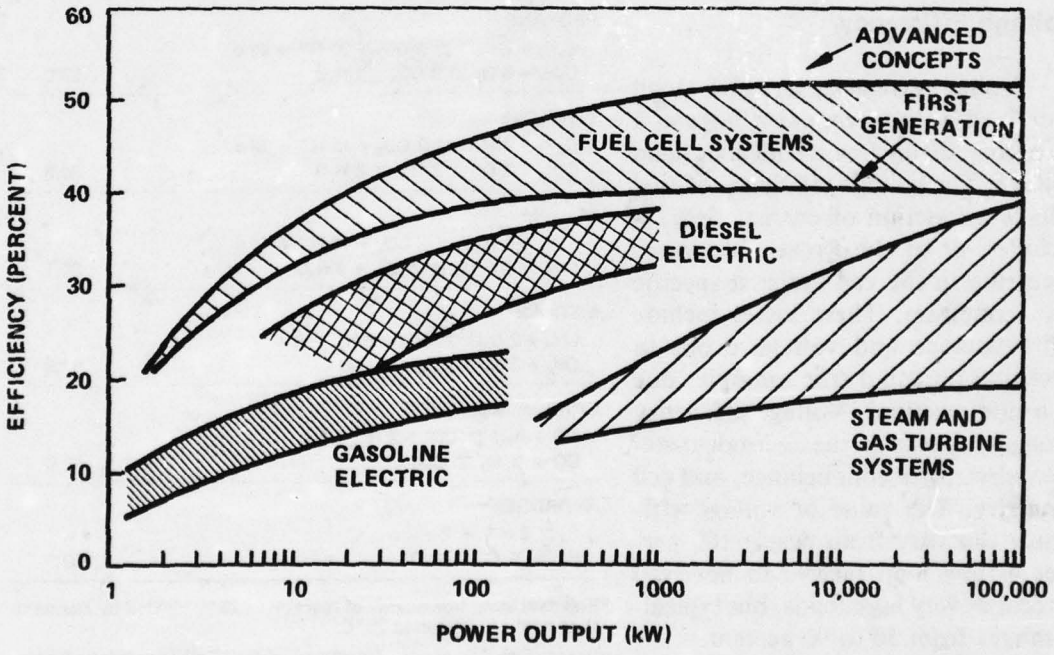
Some of the liquid reactants (for example, hydrazine and hydrogen peroxide) are lost by spontaneous decomposition. Some fuels, such as methanol, cannot always be brought into complete reaction because they are oxidized in several steps, the last of which may proceed slower than the others. The fuel may then fail to be oxidized to the expected end product. Reaction efficiency is the ratio of the fuel consumed electrochemically to the fuel supplied. These efficiencies are normally 95 percent or higher.

Output Interface Device Efficiency

Output interface device efficiency may be defined as the ratio of delivered power to DC power supplied by the fuel cell. DC power may provide mechanical outputs through the use of DC motors, which have an efficiency of 80 to 90 percent when operated at rated loads. DC heating grids will operate at nearly 100 percent efficiency. DC may be converted to AC either by a motor-generator or solid-state inverter. Both of these devices are capable of 80 to 90 percent efficiencies.

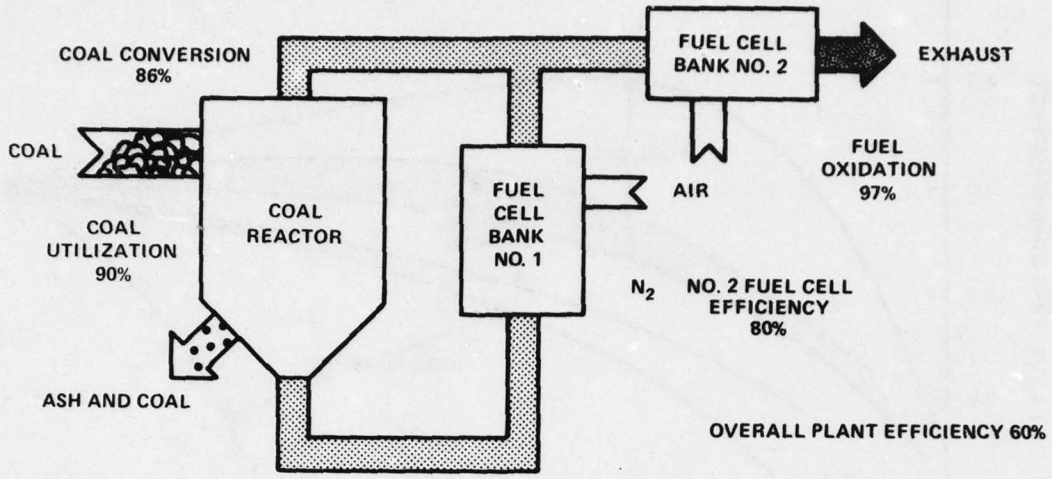
Comparison of Power System Efficiencies

UTC has determined the efficiencies of a range of power plants that use gas or liquid hydrocarbon fuels to provide AC power (Figure 15-11). The efficiency estimates for a proposed Westinghouse multimegawatt coal-fueled power plant with DC output are shown in



Source: United Technologies Corporation, Testimony Before Subcommittee on Energy Research, Development, and Demonstration, Committee on Science and Technology, U.S. House of Representatives, 27 February 1975.

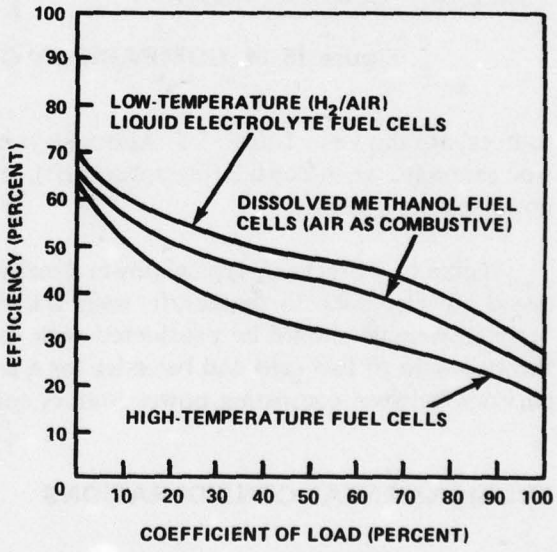
Figure 15-11. COMPARISON OF POWER SYSTEM EFFICIENCIES



Source: E. F. Sverdrup and others, "A Fuel Cell Power System for Central-Station Power Generation Using Coal As a Fuel," *Electrocatalysis of Fuel Cells* (Seattle, WA: University of Washington Press, 1972).

Figure 15-12. EFFICIENCIES OF A SOLID ELECTROLYTE FUEL CELL POWER PLANT

Figure 15-12. The efficiencies of a fuel cell also vary as a function of load, as shown in Figure 15-13. (The curves in Figure 15-13 do not include the input or output interface efficiencies.) UTC plotted similar data for a fuel cell with input and output interface devices in Figure 15-14, and compared the fuel cell with gas turbine, diesel, and gasoline electrical power generation systems. There are two important observations to be made about the efficiency of fuel cells relative to conventional energy systems. The first is that fuel cell systems usually offer higher efficiencies than conventional systems. The second is that the efficiency of fuel cell systems improves with decreasing load over wide variations of power output.

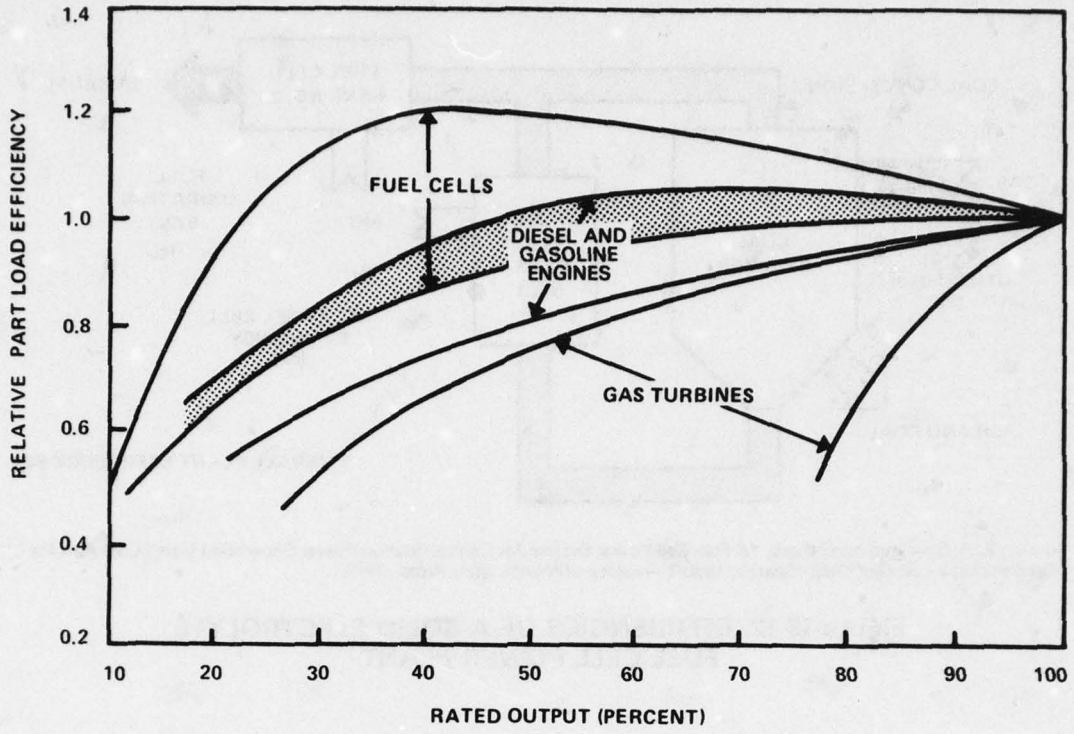


Source: Carl Berger, ed., *Handbook of Fuel Cell Technology* (Englewood Cliffs, NJ: Prentice-Hall, Inc., 1968).

Figure 15-13. EFFICIENCY AS A FUNCTION OF LOAD

TECHNICAL CHARACTERISTICS

Space requirements for typical fuel cells, compared with conventional power



Source: United Technologies Corporation.

Figure 15-14. COMPARISON OF PART LOAD EFFICIENCIES

sources, are shown in Table 15-3. Although volume is normally the important size parameter (for example, when considering spacecraft), the most important parameter in large utility power plants is area.

Table 15-4 lists some typical power density values for fuel cells, compared with conventional power plants. In spacecraft, weight/kWh is more important than weight/kW; thus, fuel cell weights should be considered with their fuel and oxidant included. Figure 15-15 shows weight of fuel cells and batteries for a 200 W unit. Table 15-5 lists some weight comparisons between competing power sources considered for the Apollo space missions.

ENVIRONMENTAL CONSIDERATIONS

Noise

While the basic fuel cell is a quiet device, there are some potentially noisy devices that can be part of a fuel cell system—for example, reformers, coal gasification plants, cooling fans, and transformers. Preliminary design noise estimates, not including transformer noise, for the UTC 20 MW TARGET fuel cell power plant indicate that it will be inaudible at

Table 15-3. SPACE REQUIREMENTS FOR FUEL CELLS AND OTHER POWER SOURCES

Space Required		Remarks
m^3/kW	ft^3/kW	
0.075	2.64	Provisional specifications for UTC's PC-16 12.5 fuel cell using natural gas or propane for fuels; complete power system (reformer, liquid electrolyte fuel cell, and inverter) to supply AC power for remote site, portable, or emergency applications.
$5.95, 10^{-3}$	0.21	Alsthom's 1 kW hydrazine-hydrogen peroxide unit.
$3.26, 10^{-3}$	0.115	Westinghouse solid electrolyte fuel cell power unit optimization study (for fuel cell only).
$5.66, 10^{-3}$	0.2	Westinghouse study on central-station power generation (for fuel cell only, operating at 80 percent efficiency).[a]
0.02-.03	0.71-1.06	Low-temperature hydrogen with liquid electrolyte (fuel cell only).
0.005-.015	0.18-0.53	Low-temperature hydrogen with solid electrolyte (fuel cell only).
0.06-.09	2.12-3.18	Low-temperature dissolved methanol (fuel cell only).
0.015-.025	0.53-0.88	Low-temperature dissolved hydrazine (fuel cell only).
0.0142	0.50	11.2 kW electric automobile design study (hydrogen fuel) (fuel cell only).
0.0186[b]	0.20[b]	Estimates for UTC's 20 MW TARGET power plant.
$3.01, 10^{-3}$	0.106	Internal combustion engine.
0.05	1.766	Gasoline engine with an alternator unit (10 kW size).
0.06	2.119	Diesel engine with an alternator unit (100 kW size).
0.33	11.654	Lead/acid batteries used to 0.1 of their capacity.
0.10	3.531	Ni-$CaCl_2$ batteries used to 0.2 of their capacity.

[a]The coal gasification bed volume requirements are 0.25 to 0.4 ft^3/kW.

[b]*Area per kW*. 0.2 ft^2/kW (0.0186 m^2/kW).

Sources: A. D. S. Tantram, "Fuel Cells: Past, Present, and Future," *Energy Policy,* Vol. 2, No. 1, March 1974; E. F. Sverdrup and others, "Design of High Temperature Solid-Electrolyte Fuel-Cell Batteries for Maximum Power Output Per Unit Volume," *Energy Conversion, An International Journal,* Vol. 13, No. 4, December 1973; E. F. Sverdrup and others, "A Fuel-Cell Power System for Central-Station Power Generation Using Coal as a Fuel," *From Electrocatalysis to Fuel Cells* (Seattle, WA: University of Washington Press, 1972); Carl Berger, ed., *Handbook of Fuel Cell Technology* (Englewood Cliffs, NJ: Prentice-Hall, Inc., 1968); W. T. Reid, "Fuel Cells for Practical Energy Conversion Systems," *From Electrocatalysis to Fuel Cells* (Seattle, WA: University of Washington Press, 1972); W. J. Lueckel and others, "Fuel Cells for Dispersed Power Generation," *IEEE Winter Meeting,* Paper T-72, New York, NY, 30 January-4 February, 1974; and J. Verstraete and others, "Fuel Cell Economics and Commercial Applications," *Handbook of Fuel Cell Technology* (Englewood Cliffs, NJ: Prentice-Hall, Inc., 1968).

about 30 m in a residential neighborhood. Although this system has some soundproofing, the noise level could be further reduced by additional acoustical baffling.

Exhaust Emissions

Fuel cells usually have low levels of exhaust emissions because the chemical reaction takes place at low temperatures. Some examples of fuel cell exhaust emissions are shown in Table 15-6.

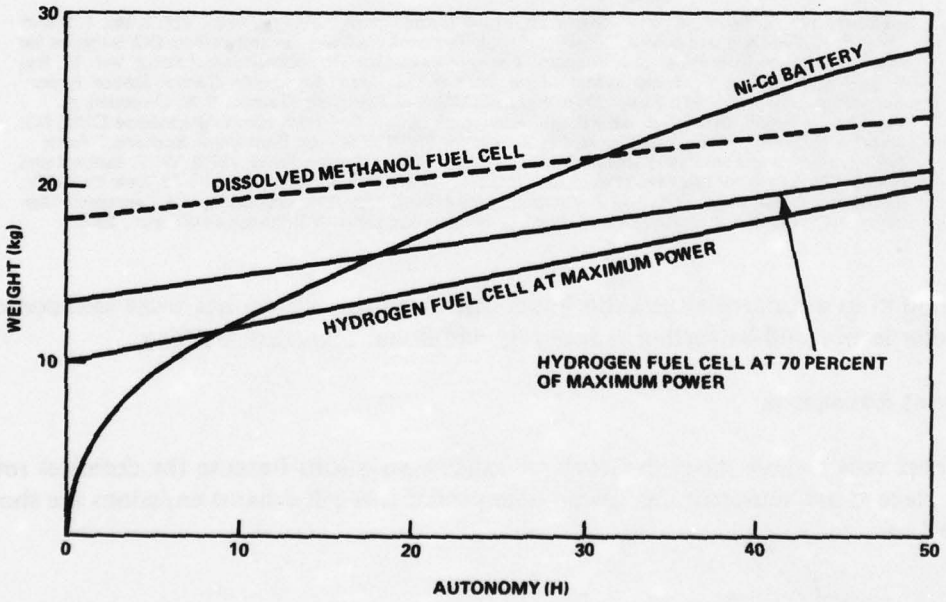
ECONOMICS

The economic evaluation of competing energy conversion systems in its simplest form

Table 15-4. POWER DENSITIES OF FUEL CELLS AND OTHER POWER SOURCES

Power Density		Remarks
lb/kW	kg/kW	
17.0	7.71	UTC PC15A-1 space system fuel cell; also two of these used in the Deep Submergence Rescue Vehicle (DSRV).
19.0	8.62	UTC space shuttle orbiter fuel cell.
80.0	36.29	Provisional specifications for UTC PC-16 fuel cell; based on total system weight including reformer, fuel cell and DC to AC inverter. System designed to use natural gas or propane.
33.1 to 44.1	15 to 20	Low-temperature hydrogen fuel cells with liquid electrolyte (fuel cell only).
22.0 to 33.1	10 to 15	Low-temperature hydrogen fuel cells with solid electrolyte (fuel cell only).
66.1 to 99.2	30 to 45	Low-temperature dissolved methanol fuel cells (fuel cell only).
22.0 to 33.1	10 to 15	Low-temperature dissolved hydrazine fuel cells (fuel cell only).
6.61	3.00	Internal combustion engines.
8.82	4.00	Gasoline engines with transmission.
17.64	8.00	Diesel engines with transmission.
55.12	25.00	Gasoline engines with alternator unit (10 kW size).
77.16	35.00	Diesel engines with alternator unit (100 kW size).
1322.77	600.00	Lead/acid batteries used to 0.1 of their capacity.
440.92	200.00	NiCd batteries used to 0.1 of their capacity.
3.31	1.50	Wankel engine (projection).

Sources: A. D. S. Tantram, "Fuel Cell Economics and Commercial Applications," *Handbook of Fuel Cell Technology* (Englewood Cliffs, NJ: Prentice-Hall, Inc., 1968); and United Technologies Corporation.



Source: J. Verstraete and others, "Fuel Cell Economics and Commercial Applications," *Handbook of Fuel Cell Technology* (Englewood Cliffs, NJ: Prentice-Hall, Inc., 1968).

Figure 15-15. WEIGHT OF BATTERY AND FUEL CELLS FOR 200 W UNIT

Table 15-5. COMPARISONS OF WEIGHTS FOR POWER SOURCES FOR THE APOLLO MISSION

Power Source	Approximate Weight for Mission[a] (lb)	Command and Service Module[b] (Percent)
Lead-acid batteries	44,000	70
Silver-zinc batteries	12,000	15
Hydrogen-oxygen engine generator	6,500	10
Ion exchange fuel cell (General Electric Company)	2,500	4
Bacon fuel cell (UTC)	1,600	2-6

[a]The weights are all up weights including fuel, oxidant, tankage, electrolyte, etc., for the Apollo mission requirements:
Mission time: Up to 400 hours
Peak power: About 3 kW
Energy storage: About 800 kWh.

[b]Command module + service module = 62,720 lb.

Source: A. D. S. Tantram, "Fuel Cells: Past, Present and Future," *Energy Policy*, Vol. 2, No. 1, March 1974.

Table 15-6. COMPARISON OF EMISSION CONCENTRATION/ ENERGY OUTPUT (Nanogram/Joule[a])

Pollutant	Natural Gas-Fired Central Station[b]	Natural Gas—Fuel Cells[b]	Natural Gas—Federal Solid-fuel Effluent Standard[c]	Gas from Coal—ECAS Conceptual Plant[d]	Naphtha—Fuel Cell Power Plant[d,e]	
					4.8 MW Demonstrator (Design Goals)	1 MW Test Unit
Sulfur dioxide	37.8	0.0378	515.9	318.2	0.01	0.65
Nitrogen oxides	504.0	30.2	301.0	<12.9	9.0	9.0
Hydrocarbons	352.8	29.0	—	negligible	—	—
Carbon monoxide	—	—	—	0.0069	—	—
Particulates	12.6	0.0038	12.6	<38.7	0.001	nondetectable

[a]To convert to lb/million Btu, multiply nanogram/Joule by 0.00232.

[b]UTC data.

[c]IGT GasScope, No. 43, Summer 1978.

[d]IEEE Spectrum, November 1978.

[e]At rated power; values shown represent concentration/energy input.

requires the combination of fixed and proportional costs to determine a cost/kWh. A typical situation for fuel cells is shown in Figure 15-16. In the example shown, the most economical operation would occur at a 53 percent load factor. If, for example, a power plant were required to provide an average 53 kW load, it would be economically desirable to build a 100 kW power plant, resulting in a large reserve capacity. It also could provide economical power for at least a 40 percent reduction in its 53 kW nominal load.[8,9]

In a conventional electrical power generation system (for example, a steam tur-

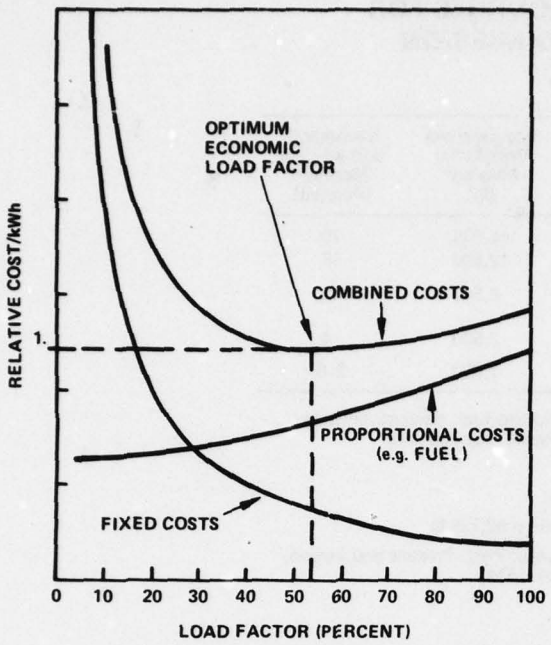


Figure 15-16. COST VARIATIONS AS A FUNCTION OF LOAD FACTOR

bogenerator), the proportional costs curve would have a reversed slope and a somewhat different shape. (The primary cause of the change would be the differing efficiency characteristics.) As a result, the combined costs curve would have an optimum economic load factor near 100 percent and the relative cost/kWh would rise rapidly for lower load factors. Thus, the optimum plant would have a small reserve capacity, and energy at the lower load factors would be relatively expensive. However, the initial capital costs usually would be much lower than the competing fuel cell power plant.

The current cost of multimegawatt fuel cell power plants, using liquid or gaseous fuels, is about $1,500/kW. It will probably take over 1,000 MW of fuel cell production to achieve the $350/kW target level ($800/W). For coal-fueled fuel cell power plants, a target level of $800/W has been established by the Electric Power Research Institute.

In summary, fuel cells compare economically when the required fuel is hydrogen and the required output is DC power, the power plant has a large peaking requirement relative to its nominal load, and one of the following favorable factors is exploited:

- Modular construction, which allows a utility to purchase the power capacity it presently needs with the flexibility to add capacity later as required, and good space utilization (for example, in ships).
- Higher efficiencies, which result in lower fuel consumption and costs.
- Location near application sites, which reduces electrical distribution costs.
- Component structure which can be mass produced.
- Compliance with many of the noise and air pollution regulations as well as other environmental requirements with only minimum modifications.

An unfavorable factor (due to the newness of the technology) is the uncertain data on production and operating costs and other economic factors. Another disadvantage is that the anticipated life of some fuel cell system components is less than that of conventional power system components.

FUEL CELL R&D AND APPLICATIONS

The fuel cell R&D program in the United States is active, as shown in Table 15-7. Major recent fuel cell applications are summarized in Table 15-8; Figures 15-17, 15-18, and 15-19 show details on three of these applications. Development of large-scale fuel cell systems, particularly Fuel Cell Generator 1 (FCG-1) (phosphoric acid) and an advanced system (molten carbonate), is being emphasized. The phosphoric acid fuel cell, now in production, is to be tested in a 4.8 MW plant, then in a dual energy use demonstration. Commercial use

Table 15-7. FUEL CELL PROJECTS

Description	Developer	Sponsor
Market assessment of fuel-cell total-energy systems	Resource Planning Associates, Inc. Washington, D.C.	DOE through Oak Ridge National Laboratory
Assessment of the potential role of advanced generation technologies in small utilities	Burns and McDonnell Engineering Company Kansas City, Missouri	EPRI (Project RP918)
Assessment of the integration of on-site fuel cells for selected industrial applications	Arthur D. Little, Inc. Cambridge, Massachusetts	
Economic assessment of the application of heat pumps to fuel cell total energy systems	Westinghouse R&D Center Pittsburgh, Pennsylvania	
Assessment of the conservation and economic benefits of fuel cell applications in residential and commercial buildings	United Technologies Corporation Power Systems Division South Windsor, Connecticut	DOE (Contract EY-76-C-03-1264)
Environmental assessment of residential energy supply systems using fuel cells	SRI International Menlo Park, California	EPA
Assessment of fuel cell applications for less developed countries	Energy System Research Group, Inc. Rochester, New York	
Assessment of various fuel cell power system configurations utilizing waste-derived fuels	Energy Research Corporation Danbury, Connecticut Science Applications, Inc. LaJolla, California	ERC, SAI, DOE (Contract EC-77-C-03-1492)
Fuel cell power sources for electric vehicles	U.S. Army (MERADCOM) Fort Belvoir, Virginia Brookhaven National Laboratory Upton, New York Los Alamos Scientific Laboratory Los Alamos, New Mexico	DOE
By-product hydrogen utilization in fuel cells applications	Engelhard Minerals and Chemicals Corporation Edison, New Jersey	
Assessment of dual energy use fuel cells	Mathtech, Inc. Washington, D.C.	EPRI (Project RP1135)
Phosphoric acid technology improvement	United Technologies Corporation Power Systems Division South Windsor, Connecticut	EPRI (Projects RP114 and RP842-4) DOE (Contract EY-76-C-03-1169)

Table 15-7. FUEL CELL PROJECTS (CONT'D)

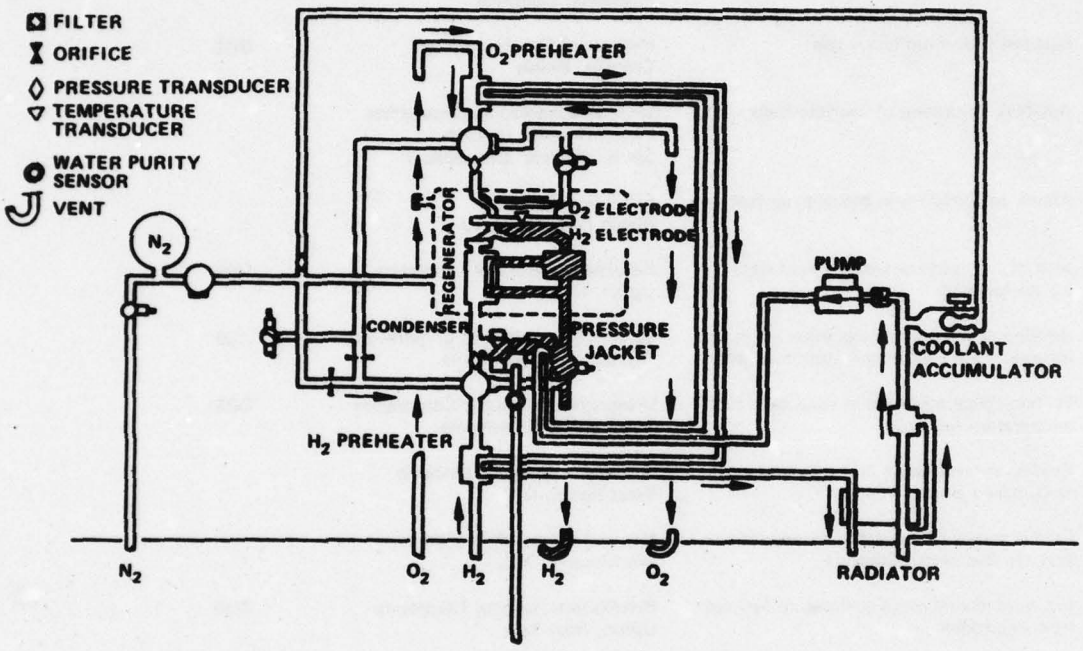
Description	Developer	Sponsor
1.5 kW portable power plant	Energy Research Corporation Danbury, Connecticut	U.S. Army (MERADCOM) (Contract DAAG53-76-C-0118)
Total energy fuel cell system	Energy Research Corporation Danbury, Connecticut	DOE (Contract EC-77-C-03-1404)
Phosphoric acid fuel cell cathode	Energy Research Corporation Danbury, Connecticut	EPRI (Project RP1200-1)
Phosphoric acid catalyst sintering	Exxon Research and Engineering Company Government Research Laboratories Linden, New Jersey	EPRI (Project RP583)
Development of carbon substrates for phosphoric acid cathodes	Stonehart Associates, Inc. Madison, Connecticut	EPRI (Project RP1200-2)
Platinum phosphoric acid cathode catalysts	Case Laboratories for Electrochemical Studies Chemistry Department Case Western Reserve University Cleveland, Ohio	EPRI (Project RP634)
Kocite as a cathode substrate	UOP, Inc. Des Plaines, Illinois	U.S. Army (MERADCOM)
	Energy Research Corporation Danbury, Connecticut	DOE (Contract DAAG53-76-C-0014) EPRI (Project RP1200-3)
Use of TAA complexes in primary fuel cells	ECO, Inc. Cambridge, Massachusetts	
Molten carbonate fuel cell performance	United Technologies Corporation Power Systems Division South Windsor, Connecticut	EPRI (Project RP114)
System constraints for molten carbonate fuel cells in power generation	General Electric Company Research and Development Center Schenectady, New York	
ERC molten carbonate fuel cell program	Energy Research Corporation Danbury, Connecticut	
Synthesis of lithium aluminate for molten carbonate fuel cell applications	Argonne National Laboratory Argonne, Illinois	
Sintering retardation by interface control	Northwestern University Evanston, Illinois	
Electrolytic studies of molten carbonate fuel cell tiles and electrodes	Oak Ridge National Laboratory Oak Ridge, Tennessee	DOE (Contract W-7405-eng-26)
Half cell heat release and modeling overview	Physical Sciences, Inc. Woburn, Massachusetts	DOE (Contract EY-76-C-03-1254)
Cost-effective electrolyte tiles	Institute of Gas Technology IIT Center Chicago, Illinois	DOE EPRI (Project RP1085-2)
Assessment of cost and availability of fuel cell fuels	Arthur D. Little, Inc. Cambridge, Massachusetts	EPRI (Project RP1042)

Table 15-7. FUEL CELL PROJECTS (CONT'D)

Description	Developer	Sponsor
Processing heavy fuels for fuel cells	Catalytica Associates, Inc. Santa Clara, California	EPRI (Project RP919)
Steam reforming methanol containing other alcohols	Jet Propulsion Laboratory Pasadena, California	U.S. Army
Autothermal and steam reforming of distillate fuel oils	Jet Propulsion Laboratory Pasadena, California	U.S. Army (MERADCOM) EPRI (Project RP1041-2)
High-temperature steam reforming options for electric utility fuel cells	Kinetics Technology International Corporation Pasadena, California	EPRI (Project RP1041-1)
Fuel-cell fuels from heavy oils	Institute of Gas Technology Chicago, Illinois	DOE
Adiabatic reforming of distillate fuels	United Technologies Corporation Power Systems Division South Windsor, Connecticut	
Anode performance in the coal/air fuel cell	SRI International Menlo Park, California	
Analysis of overpotentials in solid electrolyte fuel cells	Brookhaven National Laboratory Upton, New York	DOE
Development of a practical interconnection for solid state high-temperature fuel cells	Westinghouse Electric Corporation Pittsburgh, Pennsylvania	DOE
Technological advances in solid state high-temperature fuel cells	Westinghouse Electric Corporation Pittsburgh, Pennsylvania	DOE
Studies in preparation and polarization of CeO_2-based electrolytes	National Bureau of Standards Washington, D.C.	
Critical survey of interstitial compounds as acid cell fuel electrocatalysts	National Bureau of Standards Washington, D.C.	
In-situ regeneration of surfaces of fuel cell-type electrodes	Brookhaven National Laboratory Upton, New York	DOE
Advanced hydrogen/oxygen solid polymer electrolyte fuel cells for space missions	General Electric Company Wilmington, Massachusetts	NASA
Methanol/air fuel cell for terrestrial mobile applications utilizing solid polymer electrolytes	General Electric Company Wilmington, Massachusetts	U.S. Army (MERADCOM)
Regenerative fuel cells for energy storage through the use of solid polymer electrolytes	General Electric Company Wilmington, Massachusetts	NASA DOE
Intermediate temperature carbonate fuel cells	General Electric Company Wilmington, Massachusetts	DOE
Alternative electrolytes for acid fuel cells	EIC Corporation Newton, Massachusetts	DOE (Contract EY-76-C-03-1363)
Alternative acid electrolytes	Chemistry Department The American University Washington, D.C.	

Table 15-7. FUEL CELL PROJECTS (CONT'D)

Description	Developer	Sponsor
Cost/efficiency of molten carbonate fuel cell integrated with Texaco coal gasifier	Fluor Engineers and Constructors, Inc. Los Angeles, California	EPRI (Project RP239)
Research molten carbonate anode sintering	Northwestern University Evanston, Illinois	EPRI (Project RP371)
Evaluation of heat exchanger materials	Lockheed	EPRI (Project RP1041-3)

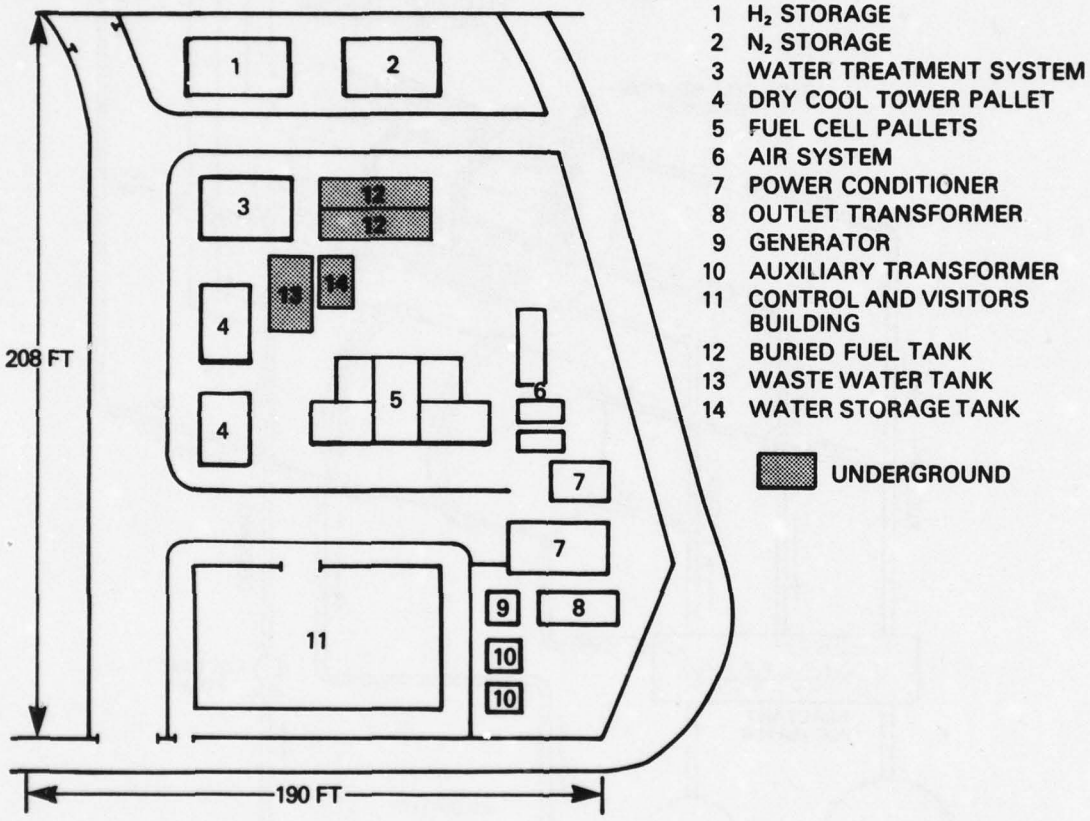


Source: A. B. Hart and G. J. Womack, *Fuel Cells Theory and Application* (London: Chapman and Hall, 1967).

Figure 15-17. PROJECT APOLLO FUEL CELL

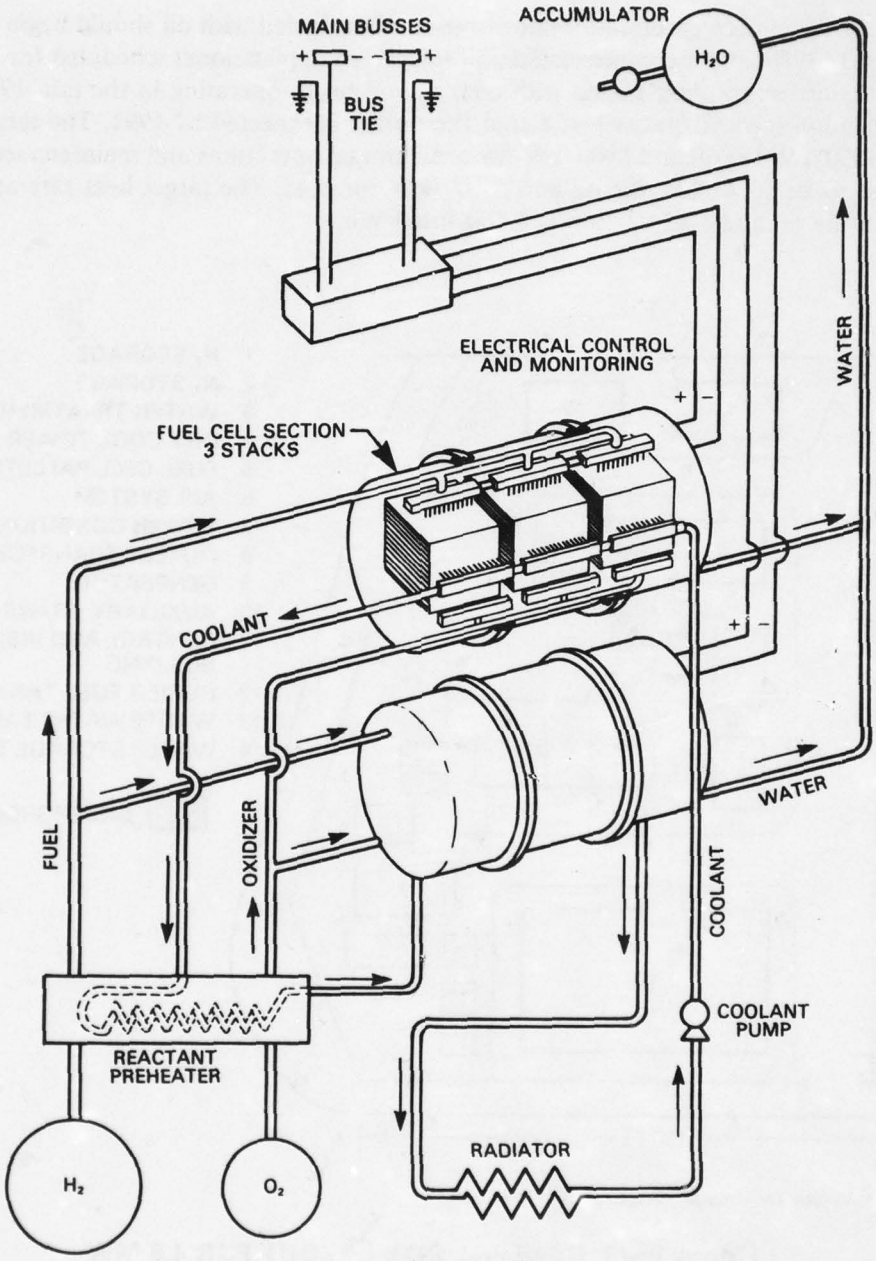
(dispersed applications) of this cell should begin in 1983–85. The target capital cost is $350/kW, with an annual operations and maintenance cost of $0.30/kW.[10]

A 5 MW molten carbonate demonstration plant fueled with oil should begin operating in the early 1980s, with commercialization (dispersed applications) scheduled for 1988. A 5 MW demonstration plant fueled with coal should begin operating in the mid-1980s; commercialization (central station) of a coal fired plant is expected by 1992. The target capital cost is $350/kW for oil and $800/kW for coal; annual operations and maintenance costs are expected to be $0.30/kW for oil and $1.00/kW for coal. The target heat rate at full load for both the oil and coal options is 7,500 Btu/kWh.[10]



Source: United Technologies Corporation.

Figure 15-18. GENERAL SITE LAYOUT FOR 4.8 MW FUEL CELL DEMONSTRATOR



Source: Wolf Vielstich, *Fuel Cells, Modern Processes for the Electrochemical Production of Energy* (New York: Wiley Interscience, 1965).

Figure 15-19. GEMINI SPACECRAFT FUEL CELL

Table 15-8. MAJOR RECENT FUEL CELL APPLICATIONS

Model (Manufacturer)	Specifications	Discussion
Gemini spacecraft fuel cell (General Electric Company)	Maximum rated power: complete system—2 kW per fuel cell battery—1 kW Nominal voltage—27 volts DC Water production/kWh—1 pint	Cells were designed for simplicity, reliability, and light weight rather than high conversion efficiency. The basic cell has the electrolyte confined in an ion-exchange membrane based on sulfonated polystyrene. The electrodes, which contain 10–40 mg/cm² of platinum and palladium, are directly in contact with the membrane. Thirty-two cells in series make a stack; three stacks in parallel compose a battery; the system is composed of two batteries.[a,b]
Project Apollo fuel cell (Model PC3A-2) (United Technologies Corporation)	Maximum rated power—2.295 kW Normal power range—0.563 to 1.420 kW Voltage range—27 to 31 volts Reactant consumption at 1.42 kW—1.166 lb/hr (maximum) Power plant weight—200 lb (exclusive of mounting provisions) Product water pH—6 to 8 Life—more than 400 hours	Cell is redesign of Bacon Cell to allow weightlessness operation and lower operating pressures. The operating pressure was reduced from 600 to 50 psi to reduce the need for heavy components by increasing the potassium hydroxide concentration from 45 to 85 percent and operating the cell at 250°C instead of 200°C.[a]
ASEA submarine power plant (ASEA of Sweden)	Maximum rated power—200 kW	Power plant is made up of ten 20 kW modules. Ammonia is cracked and the hydrogen formed is supplied to the hydrogen-oxygen battery. The nitrogen is condensed in a refrigeration system. The cells operate with nickel boride and silver catalysts. The submarine was never built.[b]
PC-11 (United Technologies Corporation)	Maximum rated power—12.5 kW Fuel—natural gas	Sixty-five of these experimental power plants were installed at 35 sites between 1970 and 1975 as part of an advanced research project for gas energy transformation. The plants were operated and serviced by utility company personnel in apartments, stores, single-family homes, small industrial plants, and electrical utility substations.[c]

Table 15-8. MAJOR RECENT FUEL CELL APPLICATIONS (CONT'D)

Model (Manufacturer)	*Specifications*	*Discussion*
GM electrovan power plant (General Motors/Union Carbide)	Maximum power—32 kW Peak electric motor rating—160 kW Fuel—liquid hydrogen (6 kg max.) Oxidizer—liquid oxygen (48 kg max) Vehicle maximum range—150 miles	A minibus built by General Motors Corporation was equipped with a 32 kW Union Carbide fuel cell. The liquid reactants were carried in vacuum tanks. In spite of a doubling of vehicle weight, a speed of 60 MPH could be attained from rest in 30 seconds. This compared favorably with the 23 seconds for the original 225 HP vehicle.[h]
U.S. Navy Deep Submergence Rescue Vehicle (DSRV) fuel cell (United Technologies Corporation)	Maximum rated power—22 kW Nominal regulation—100 to 140 vdc Energy delivery—700 kWh Total system weight—less than 9,500 lb	Cell is being constructed for the Navy for installation on the DSRV. The power system consists of two PC15A-1 fuel cell power plants installed in containment vessels and a reactant supply system consisting of containment vessels for the storage of gaseous hydrogen, gaseous oxygen, and fuel-cell generated product water. The fuel cell power system will be capable of automatic continous operation in sea water depths to 1,525 m.[c]
Fuel cell for Space Shuttle Orbiter (Model PC17) (United Technologies Corporation)	Maximum rated power—12 kW Voltage regulation—28.5 to 32.5 volts DC Useful life—5,000 hr Weight—228 lb	Cells are being developed under contract with Rockwell International Corporation. A set of three power plants will be delivered for each Orbiter Vehicle; 15 power plants are to be delivered between July 1976 and December 1980.[c]
40 kW demo (United Technologies Corporation)	Maximum rated power—40 kW Fuel—natural gas	Cells are a follow-on development to the PC-11 program. The objective of the program is to test 50 40 kW plants in a variety of applications between 1979 and 1981, and to attain a commercially available product by 1982. The program is being supported by the Department of Energy and the Gas Research Institute.[c]

Table 15-8. MAJOR RECENT FUEL CELL APPLICATIONS (CONT'D)

Model (Manufacturer)	Specifications	Discussion
4.8 MW demonstrator[a] (United Technologies Corporation)	Heat rate—9,300 Btu/kWh at rated power Maximum rated power—4.5 MW (net AC) at sea level and 350°C at unity power factor Design life—20 years (with scheduled overhaul and maintenance Rated power life—1 year (with initial cell stack assemblies) Fuels—naphtha or selected kerosines, or natural gas (option) Load-response time minimum power to rated output—15 seconds 35 percent power to rated output—0.5 seconds Electrical output power form—3 phase; 60 ± 0.1 Hz; independent control of both real and reactive power within system rating Voltage—13.8 kV Fault currents—under line-fault conditions, output current will not exceed 1.1 per unit on an rms basis over one cycle Operation control—automatic, from remote or on-site controller modes—load, spinning reserve, standby off, emergency off, and no load power-factor correction start—4 hours from 21°C Miscellaneous ambient temperature—−34 to 43°C acoustic noise—55 db(A) m from power plant perimeter heat-rejection method—air cooled (dry cooling tower)	A 4.8 MW version of the Fuel Cell Generator 1 (FCG-1) power plant will be designed, built, and tested in a Consolidated Edison Company of New York site by 1980. Operation of the FCG-1 pilot plant in 1976 and 1977 showed that a plant fueled by naphtha could provide large amounts of energy to a utility system while satisfactorily meeting the industry's operational requirements for heat rate, emissions, and load-following capability.[c-e]

[a]A. B. Hart and G. J. Womack, *Fuel Cells Theory and Application* (London: Chapman and Hall, 1967).

[b]Wolf Vielstich, *Fuel Cells, Modern Processes for the Electrochemical Production of Energy* (New York: Wiley Interscience, 1965).

[c]United Technologies Corporation, Personal Communication.

[d]A. P. Pickett, "Fuel-Cell Power Plants," *Scientific American*, Vol. 239, No. 6, December 1978.

[e]E. P. Barry, R. L. A. Fernandes, and W. A. Messner, "A Giant Step Planned in Fuel-Cell Plant Test," *IEEE Spectrum*, Institute of Electrical and Electronic Engineers, New York, November 1978.

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16. MAGNETOHYDRODYNAMICS

A magnetohydrodynamics (MHD) generator directly converts the kinetic and thermal energy of gas to electrical energy. To effect this conversion, a gas is heated until it is a plasma (highly ionized and electrically conductive gas). The plasma is passed through a nozzle to convert the random motion into directed kinetic energy and then through a magnetic field, producing a Lorentz force on the positive ions and negative electrons (which flow back from the external circuit to the positive ions). Electric power is produced by the expanding plasma.[1]

MHD systems can be combined with a conventional power generator to improve efficiency. The overall efficiency of a fossil fuel power generation plant may be increased from a maximum of 40 percent to 50 or 60 percent, realizing a significant savings in energy resources. Furthermore, an MHD system can use any conventional heat source (coal, petroleum, natural gas, nuclear), making maximum use of existing plants. An important advantage is the ease of retrofitting existing conventional generation station facilities with MHD generators. Adding MHD as a topping cycle requires the replacement of the conventional fuel furnace with the needed high-temperature combustor, plasma duct, magnet, and ancillaries, but the conventional steam generator, turbines, alternators, controls, and transmission systems generally will be usable without major modification.

Because of these advantages, research has been directed at the successful development of commercially acceptable MHD generators. Patents for MHD devices appeared as early as 1910, and a generator was introduced by Westinghouse Electric Corporation in the early 1940s. The crucial work for MHD development occurred after World War II when the idea of confining a plasma in a magnetic field was developed as a part of the thermonuclear fusion program. AVCO Everett Research Laboratory developed the world's first successful MHD generator, a closed-cycle device (using seeded argon gas) that produced 10 kW of power for 10 seconds. In the 1960s, 20 MW and 32 MW devices were built, and work began in various U.S. laboratories under sponsorship of the Department of Defense. In 1965, the USSR began the largest MHD effort to date; Japan, Poland, and West Germany also have initiated MHD programs. U.S. federal funding began for MHD commercial power application in 1970, and a major breakthrough occurred in superconducting magnet technology at the Argonne National Laboratory (ANL) in 1977. Presently, the U.S. Department of Energy (DOE) is sponsoring developmental efforts in this country, and cooperative programs with the USSR and Poland. The USSR focuses on modeling plants of increasing size and complexity using natural gas; the United States emphasizes scientific understanding of the process, using an open-cycle MHD/steam plant fired by coal. This understanding is then applied to predicting the behavior of key components, especially the MHD generator channel. Cooperation is expected to make it possible to develop MHD technology quickly and economically.

MHD THEORY

An MHD generator operates on the principle that, when an electrically conductive fluid (either liquid or gas) flows across a magnetic field, an electromotive force is induced at right angles to both the magnetic field and direction of fluid flow, causing a current to flow in an external load. With a plasma flowing within a duct at right angles to the magnetic field, the electrons and positive ions of the plasma separate to the electrodes on opposite sides of the duct creating an electric field; the electrical load is harnessed across this electric field in the external circuit.

The output power per unit volume for an MHD generator is proportional to the electrical conductivity of the working fluid, the square of its flow velocity, and the square of the magnetic flux density. Because gases, even at very high temperatures, are poor conductors, they are seeded; that is, a small amount (about 1 percent) of an easily ionized salt (such as potassium carbonate) is added to the input. In this manner, conductivities as high as 10 Siemens/m (mho/m) can be achieved at about 3,000°K with noble gases (such as argon). The flow velocity of the gas is limited to that of sonic velocity (about 1,000 m/s). Given the limits of conductivity, flow velocity, and the fact that power density is proportional to the square of magnetic flux density, research to increase magnetic flux density is critical.

The simplest type of MHD generator, named after Michael Faraday, is shown in Figure 16-1. This generator, which consists of a continuous cathode and anode separated by insulating side walls, operates efficiently only when the fluid is a liquid metal for then the electric field is perpendicular to the flow. When a gas rather than a liquid is the working fluid, electrons in the gas tend to drift perpendicular rather than parallel to the electric field (due to the Hall effect). This drift gives a longitudinal component to the electric field, which would cause short circuits if solid, continuous electrodes were used as in a simple Faraday generator. Because of the Hall effect, equipotential surfaces, perpendicular to the resultant electric field, are inclined with respect to the axis of the channel. Therefore, if each anode is connected electrically to the cathode lying on the same equipotential surface, the power take-off can be accomplished at the ends of the channel or at intermediate points.

At high magnetic flux densities, high current densities, or low pressures, the equipotential surfaces turn from diagonal to perpendicular, short-circuiting opposite anodes and cathodes. Under this condition, the electric field is directed horizontally along the channel in the direction of flow of the fluid; thus the external load is connected between the two ends of the channel. This output voltage consists solely of the Hall field, and such generators are named after Hall.

MHD SYSTEMS

MHD generators can be classified as open cycle or closed cycle. Open-cycle systems use seeded combustion products as the working fluid, and, after recovering the seed material, the working fluid is rejected into the atmosphere. Closed-cycle systems recycle a noble gas (or liquid metal) as the working fluid. Figure 16-2 is a schematic of an open-cycle coal-fired MHD system combined with a conventional power generator. The combined-cycle, MHD/

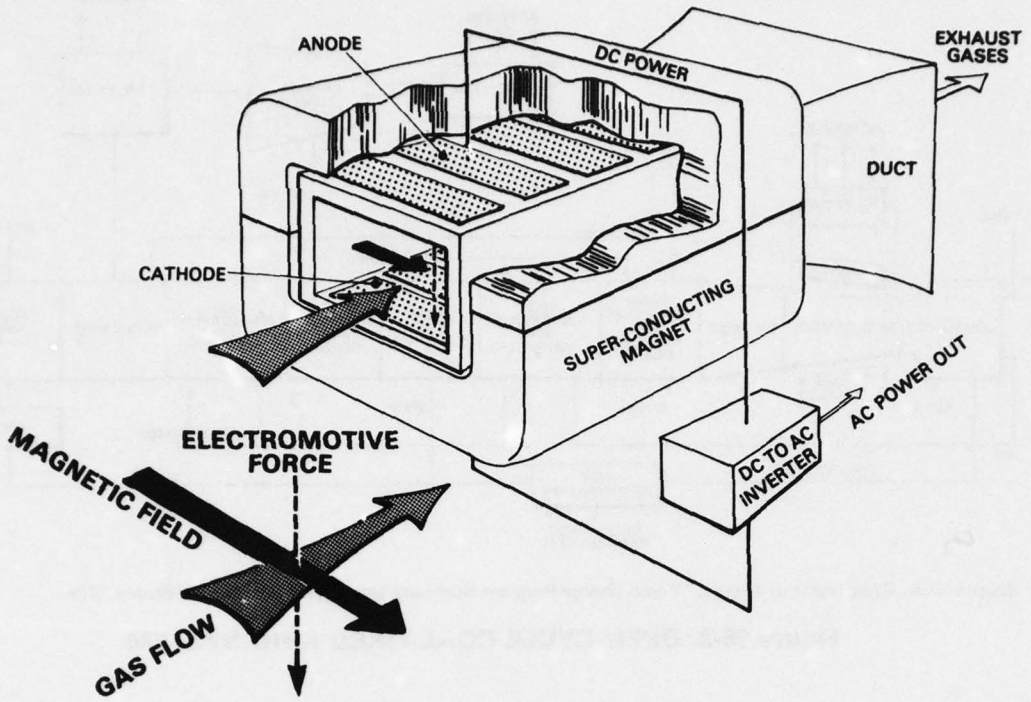
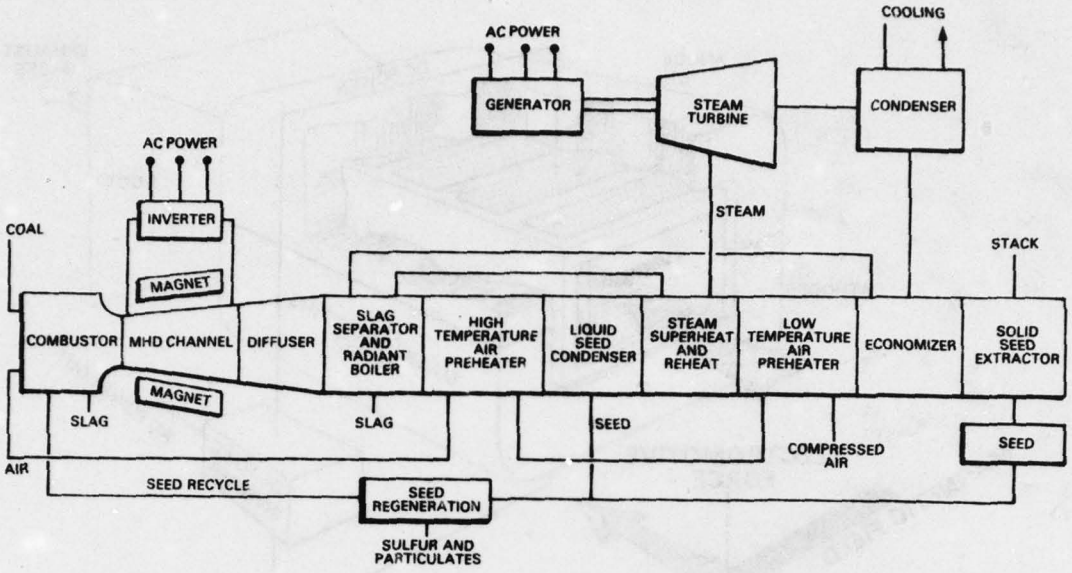


Figure 16-1. MHD GENERATOR CONFIGURATION—SEGMENTED FARADAY CHANNEL

steam power plant system consists of two major subsystems. The MHD topping cycle includes the coal combustor, generator (or channel), inverter, and magnet. The second subsystem includes the heat and seed recovery components, air preheater, steam boiler, pollution control equipment, and additional components for thermal regeneration and seed recovery. The working fluid is eventually rejected to the atmosphere, hence the term open-cycle. Combustion air must be preheated so that gases from fossil fuel combustion can reach temperatures above 2,200 °C. The combustion gases are then seeded and used directly as the working fluid for the MHD generator. Seed material must then be separated from the exhaust gases and recycled to the incoming combustion flow. After MHD topping, exhaust gases are used to generate steam via waste heat boilers. A high flame temperature is necessary to maintain high electrical conductivity and conversion efficiency in open-cycle MHD generators. Combustion of coal or residual oil with air preheated to 1,200 °C produces a flame temperature of approximately 2,380 °C at design operating pressures of 75 to 150 psi. A conventional steam power plant that uses MHD topping over a temperature difference of 2,380 °C to 1,870 °C could increase energy efficiency from an average 35 percent for conventional steam to about 50 percent.[2]

The closed-cycle MHD generator recycles the working fluid (normally a noble gas).



Source: U.S. Department of Energy, "Fossil Energy Program Summary Document, FY 1980," January 1979.

Figure 16-2. OPEN-CYCLE COAL-FIRED MHD SYSTEM

Heat is added to and rejected from the cycle through heat exchangers. The noble gases, which have low electron affinities, are used as working fluids in closed-cycle systems because their nonequilibrium ionization enhances their electrical conductivity. The enhanced conductivity effect allows the generator to operate at stagnation temperatures of 1,650°C, and power extraction from the fluid can be maintained at gas temperatures as low as 593°C. Also, higher gas conductivity results in higher power densities. Closed-cycle MHD generators combined with conventional power plant systems can yield a potential 50 percent combined power plant efficiency.

Possibly the most promising application for closed-cycle MHD is with nuclear heat sources. The high-temperature, gas-cooled reactor operating at about 1,315°C is an attractive heat source for the closed-cycle MHD. Since the MHD generator has no moving parts, sealing the MHD generator in with the reactor creates a self-contained, direct conversion system that may be technically feasible.

ANL is working on a two-phase liquid metal MHD generator using liquid potassium and nitrogen gas as the working fluid (see Figure 16-3). The liquid potassium and nitrogen gas are mixed at high pressure and passed through the generator. The liquid potassium and nitrogen gas then are separated, the nitrogen compressed, and both the nitrogen and liquid potassium are heated prior to repeating the cycle. Emphasis is on developing a low-temperature version of the concept in the temperature range of water reactors. The aim of the ANL research effort is to develop an energy conversion system compatible with the liquid metal fast breeder reactor (see Chapter 7), which is the reason for Navy interest in the project.[3]

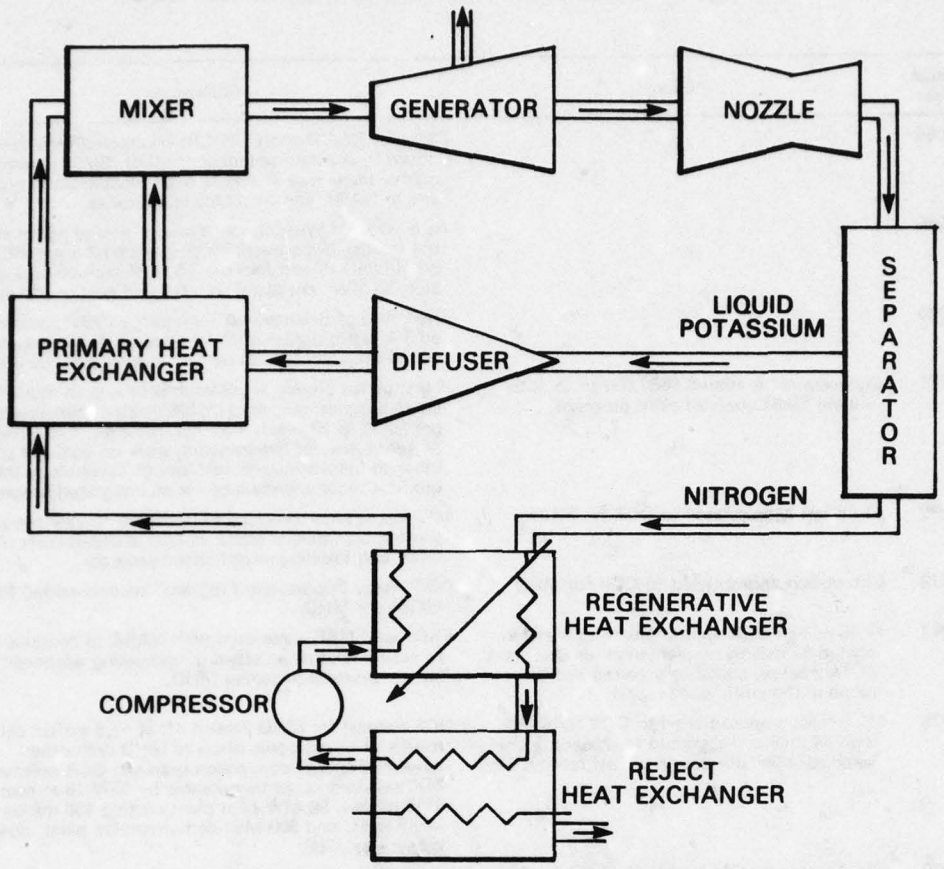


Figure 16-3. SCHEMATIC OF THE ANL BASIC TWO-PHASE FLOW LIQUID-METAL AND GENERATOR CYCLE

RESEARCH AND DEVELOPMENT

Table 16-1 summarizes legislative action on MHD R&D from FY 1964 to 1979. The present emphasis of MHD R&D evolved from the results of a 1975 Energy Conversion Alternatives Study (ECAS), sponsored by the Energy Research and Development Administration (ERDA), National Aeronautics and Space Administration (NASA), and National Science Foundation (NSF), under the technical direction of NASA.[4] General Electric Company (GE), Westinghouse, and United Technologies Corporation conducted the study, concentrating on baseload power system concepts. The ECAS showed that a combined-cycle, MHD/steam power plant promised the highest efficiency of all advanced baseload power systems considered. Coal-to-busbar efficiency of about 50 percent at a cost of 32 mill/kWh was predicted. In addition, sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions (without significant preprocessing of coal or stack-gas cleanup) below 0.55 lb/million Btu and 0.3 lb/million Btu, respectively, were estimated—well below then-current Environmental Protection Agency (EPA) emission standards.

Table 16-1. LEGISLATIVE ACTION ON MHD R&D

Fiscal Year	Action	Comments
1964	–	Office of Coal Research (OCR) contracted with Westinghouse to evaluate potential of MHD. Small research programs under way at AVCO (with electric utility support) and at NASA and Air Force laboratories.
1965	–	As a result of Westinghouse study, energy policy staff of the Interior Department recommended 3-stage R&D program (250 kW test facility, 2-5 MW experimental generator, 25 MW pilot plant) at estimated cost of $50 million.
1970	–	The Office of Science and Technology (OST) recommended 3-4 year program of MHD research and assessment at $4 million/year with 50 percent cost-sharing by industry.
1971	Congress appropriated $600,000 to OCR to initiate MHD nonpilot plant program.	If first phase proved successful, plan was to move to 3-stage program proposed in 1965 with commercialization predicted in 10 years. Two contracts let, 1 to University of Tennessee for experimental work on coal-gas plasma, other to Massachusetts Institute of Technology (MIT) to produce recommendations for an integrated program.
1972	$1 million appropriated to OCR for MHD.	MIT report recommended $110 million 10-year program to provide commercial MHD. Industrial contractors (AVCO, STD, and Westinghouse) joined program.
1973	$3.5 million appropriated to OCR for MHD.	OST "New Opportunity Program" recommended $3.5 million for MHD
1974	$7.45 million OCR appropriation for MHD included $2 million supplemental for University of Tennessee, specifically earmarked by name in the conference report.	ERDA and NSF contracted with NASA to conduct ECAS to assess relative potential of competing advanced energy systems including MHD.
1975	$12.5 million appropriated to OCR for MHD with $4 million designated for Montana universities to initiate design of test facility.	OCR request for MHD leveled off at $7.5 million pending results of ECAS comparison of MHD with other advanced energy conversion systems. OCR estimated 5 MW test unit could be operable by 1977-78 at cost of $115 million, 50 MW pilot plant costing $86 million ready by 1978-81, and 500 MW demonstration plant (cost unknown) by 1986.
1976	ERDA appropriation for MHD of $15.8 million in House, $76.2 million in Senate, $37.3 million conference (includes $7.8 million for transition).	ECAS Phase I report selected for further consideration in two categories: (1) "strongly recommended" and (2) "do not generally meet panel's criteria but may show promise on further detailed examination (in 1990s)." MHD in latter group.
1977	ERDA appropriation for MHD $39.99 million	House appropriations report stated, "Because of its concern for the high cost and questionable payoff of the research program in MHD the committee directs that ERDA report every 3 months on the progress of this program." ECAS Phase II conceptual design of 1,900 MW MHD plant provided comparison with other systems (fluidized-bed steam, gas turbine, fuel cell, etc.). MHD rated well in efficiency, capital costs, cost of electricity, and environmental impact. MHD estimated to require longest time to demonstration plant (19 years) at considerably higher cost ($3.07 billion escalated dollars—$1.44 billion 1975 dollars) than other alternatives. MHD rated poor on "probability for development success."
1978	ERDA requested $45.8 million based on ECAS, OST authorized $63.4 million, House appropriation $45.8 million, Senate $80 million, conference $71 million.	–
1979	DOE request $74.33 million increased by $20 million in Fossil and Nuclear Subcommittee to develop components for the Component Development and Integration Facility.	–

Source: U.S. Congress, House, Committee on Science and Technology, *Oversight, MHD Program Review,* Hearings before the Subcommittee on Fossil and Nuclear Energy Research, Development and Demonstration, 95th Cong., 2nd sess., 2 May, 4 May, and 3 August 1978.

A later study by GE for the Electric Power Research Institute (EPRI) confirmed the ECAS results. In the EPRI study, GE estimated 50 percent efficiency and cost of electricity at about 34 mill/kWh, and concluded that R&D costs are insignificant compared with the potential savings. Furthermore, the MHD concept lends itself to improved availability through modularity and redundancy. Improved availability may have the benefits of less reserve capacity for outages and of the ability to retrofit existing, less efficient, environmentally unacceptable facilities.[5]

Based on the ECAS and the EPRI study, DOE recently developed a three-phase program aimed at commercializing MHD by operating a coal-burning, open-cycle MHD/steam power generating plant in a utility environment. Phase I is the engineering for design of an MHD pilot plant; Phase II is to demonstrate commercial feasibility by building and operating a 250 MW pilot plant—the engineering test facility; and Phase III involves the design, construction, and operation of a full-scale commercial plant.

Two major government facilities are being constructed to accommodate development and integrated engineering tests on a large scale. Both facilities are scheduled for completion in 1979. The principal facility for continuous testing of engineering-scale power trains of 50 MW—the Component Development and Integration Facility (CDIF) located at Butte, Montana—will be the largest coal-fired MHD facility in the United States. The CDIF will be used to evaluate and compare the performance of MHD components and subsystems, and provide a basis for extrapolating MHD system designs to larger sizes. The CDIF will be equipped with both a superconducting and a conventional iron core magnet. The coal processing and feed system is designed for both eastern and western coals. Also, CDIF can accommodate multistage combustors with slag rejection up to 90 percent.

The second major DOE facility is the Coal-Fired Flow Facility (CFFF), located at the University of Tennessee Space Institute (UTSI) near Tullahoma, Tennessee. The CFFF will be used to test components simulating the complete MHD/steam system and the heat and seed recovery systems now being developed. Equipped with both a superconducting and a conventional iron core magnet, the CFFF will be capable of continuous operation at an input of 20 MW and short duration testing at 50 MW. Test hardware destined for the CDIF can be checked at the 50 MW level before it is shipped to the CDIF. The facility is operated by the Energy Conversion Division of UTSI, which has been involved in MHD research since 1961. This early research began on military programs, especially as the result of successful research to handle high temperatures in the 1950s through the space program. UTSI also has a close working relationship with the Tennessee Valley Authority, lending an input from the utility industry. Their past research has been directed toward the use of high-sulfur eastern coals, which the UTSI facility is designed to burn.

DOE also is conducting preliminary R&D and systems studies on closed-cycle MHD. The closed-cycle approach is not readily adaptable to coal firing, and not as advanced as open-cycle systems. Primary support for ANL's program on the two-phase liquid-metal MHD conversion system has been from the Office of Naval Research because the low-temperature version is compatible with present-day water reactors. Over the years, ANL has received additional funding from the Atomic Energy Commission, U.S. Air Force, and NSF. ANL's program has not received priority because it is viewed as a low-efficiency

system that technically is not as well advanced as open-cycle MHD; however, ANL has developed a concept for a hybrid direct coal-fired open-cycle liquid-metal MHD conversion system that may retain the best features of both systems.

Other research on closed-cycle systems is being conducted at GE using argon gas as the working fluid. This research is used to both supplement and back up the open-cycle MHD program.[2]

A part of DOE's MHD program is the cooperative effort with the USSR, which began at a joint meeting of U.S. and USSR delegates in July 1973. The USSR has had a broad MHD program for over 15 years; they built and successfully operated the world's first integrated MHD facility, known as MHD Facility U-02.[6] The U-02 plant, powered with natural gas, was connected to the Moscow power grid in 1963 and generated 100 to 200 kW. Between 1966 and 1971, the USSR built a commercial-scale MHD facility, known as U-25. At this facility, natural gas is mixed with compressed air, fed to preheaters, routed to combustion chambers, and seeded with potassium salt additives. The gas is then run through an MHD channel with a magnet. A 5 Tesla superconducting magnet, built by ANL, was installed in a bypass loop of the U-25 generator in 1977. An MHD channel, designed in the United States, also is used in the U-25 facility. The U-25 facility serves a double purpose of power supply and experimentation, and provides access to pilot-plant operating experience for U.S.-built components prior to the availability of such facilities in the United States.[7]

The United States is conducting a joint program with Poland under an agreement signed in June 1977. The Polish MHD program uses the exhaust gases of the MHD generator to gasify coal—a concept originated at AVCO Everett Research Laboratory. Two or three joint experiments will be conducted each year in Poland with little funding by the United States. These experiments include (1) design and testing of a 5 MW thermal input combustor at temperatures up to 1,200°C using alkali seed injection; (2) evaluation of construction materials, slag retention on combustor walls, and seed loss; (3) testing of two different U.S. coals; and (4) evaluation of the scale-up criteria and the design of a 20 MW thermal combustor.[3]

Recent Results

Substantial progress has been made in MHD research, including the coal combustor, MHD generator, magnet, radiant boiler, air heaters, and emission control. The steam plant that provides the bottoming cycle is closest to commercialization. Technical feasibility of the seed recovery system has been demonstrated.

The coal combustor must balance size against heat and fuel loss and slag rejection; maintain uniform pressure, temperature, and flow conditions; and achieve durable, reliable operations. Design feasibility has been demonstrated for coal, seed, and preheated air injection. The DOE Pittsburgh Energy Technology Center (PETC) has achieved slag rejection rates of 95 percent.

The MHD generator must extract electric power from the plasma. It also must control, condition, and invert the collected power from DC to AC for use in the utility power grid.

AVCO Everett Research Laboratory completed a 250-hour endurance test under electrode loading conditions simulating commercial utility conditions. The electrode erosion/corrosion performance was an order-of-magnitude better than previous tests conducted in 1976.

The present state of the art of conventional magnets is about 3 Tesla; however, an increase in magnetic flux to 5 or 6 Tesla is required. ANL produced a 36 metric ton, 5 Tesla superconducting magnet that was delivered to the U-25 facility in 1977. The facility has completed a 10-hour test using the ANL magnet.[8] GE is scheduled to complete fabrication of a 6 Tesla magnet in 1980, based on a contract signed in April 1978.[2]

The air heaters must attain the high temperatures required in the coal combustor. Two design approaches are available, including separately fired heaters (which have few design problems), and direct regenerative heaters, which are more efficient than separately fired heaters but suffer from more design problems. GE has completed a 100-hour separately fired air heater test using simulated coal firing involving ash carry-over into the heater matrix. GE attained a temperature of about 1,650°C. Fluidyne Engineering Corporation has completed a series of tests, totaling about 800 hours, on direct regenerative air heater systems. Temperatures of about 1,610°C were attained.

Promising research results have been achieved in emission control. PETC and UTSI have shown that the potassium seed additive can capture up to 95 percent of the sulfur from coal. Also, UTSI has demonstrated that nitrogen oxide emissions can be kept below the EPA standards.

Current Emphasis

Current major issues in the DOE MHD program include (1) design trade-off studies on the channel electrodes, air heater, and amount of slag reduction; (2) tests of the electricity generator, inverter, and control concept; (3) materials endurance tests; and (4) tests and data analysis to verify efficiency and scale-up calculations.[2] Results of the research in these areas is required before DOE's engineering test facility can be built in the mid-1980s.

The alternative designs for electrodes, the air heater, and amount of slag carry-over involve trade-offs between thermal efficiency and endurance (and thus cost). Cold electrodes minimize degradation of the electrodes, but at the cost of thermal loss. AVCO is conducting cold electrode tests which have shown little erosion when copper electrodes are used. Hot electrodes minimize thermal loss, but chemical reactions of the seed material with insulators at high temperatures apparently reduce electrode endurance. AVCO, Westinghouse, and the Massachusetts Institute of Technology are testing high-temperature ceramic electrode materials.

Trade-off studies on two air heater concepts (directly or indirectly heated air) are being conducted on available equipment. The directly fired air heater is incorporated into the MHD generator as a section of the bottoming cycle. It operates in a high temperature and alkali environment, but is thermally efficient. The indirectly fired air heater uses an outside fuel source; it can be smaller and less expensive, but less efficient, than the directly fired air heaters.

Currently, there are two concepts for the percent of slag carry-over: high slag rejection and high ash carry-over systems. A number of contractors are investigating high slag rejection concepts, which minimize the ash impact on downstream components, but result in both heat losses (owing to early slag removal) and higher costs for slag removal equipment. UTSI uses a high ash carry-over system that has good thermodynamic properties; however, there is concern for potential harmful effects on generator electrodes and other downstream components.

Tests are being conducted on the generator, inverter, and control concept. Technical issues include concentration of the DC power output, inversion of the DC power to AC, and control and fault protection of the system. AVCO, UTSI, and the USSR (U-25 facility) are testing the inverter and power control concept. Tests in the USSR are useful because the U-25 facility is connected to the Moscow power grid. AVCO will determine the loading mode and inverter requirements for the CDIF based on voltage consolidation tests.

MHD generator materials must have high endurance to meet the specifications of the electric utility industry. AVCO, UTSI, Westinghouse, and GE are conducting tests to obtain data for extrapolation to a utility environment, and are evaluating materials used in industries (such as the paper industry) where alkali and high-temperature environments are common. UTSI has noted that MHD generators constitute a small percentage of the MHD electric generating plant; therefore redundancy may be a solution to some of the endurance problems.[2] Assuming these cost projections and minimal electrode refurbishment costs, switching one system out for maintenance while running the redundant system will provide sufficient endurance for commercialization in the electric utility industry.

The results of the tests must be extrapolated to much larger size applications for a good analysis of design alternatives. Research is being conducted to demonstrate the efficiency of larger MHD components and systems. The results of these tests will generate data needed to define key parameters that have important effects on scale-up calculations. Thus, there will be greater confidence in the applicability of the current research results for larger power units such as the 250 MW unit at DOE's engineering test facility.

ENVIRONMENTAL ISSUES

The potential environmental benefits of a combined coal-fired MHD/steam generating power plant are significant. From a total systems point of view, benefits will accrue starting with coal mining itself. Since less coal will have to be mined per unit of electricity output, pollution associated with coal mining will be reduced. Environmental effects associated with coal transportation, including such items as vehicle pollution, traffic congestion, and noise, will be reduced.

MHD has a unique capability within the process to reduce the environmental pollution of a coal-fired power plant. The potassium carbonate seed added to the hot gas stream reacts preferentially with the sulfur in coal to produce potassium sulfate, which yields potassium carbonate and sulfur during seed regeneration. The UTSI results show that this process can remove about 95 percent of the sulfur from high-sulfur coal. In addition, the system reduces

NO_x emissions in the exhaust gas by a combination of two-stage combustion and gas stream cooling. High-temperature, fuel-rich combustion minimizes NO_x formation; NO_x formation is impeded further by controlling the cooling rate of the gas stream. Recent MHD test results show that SO_2 and NO_x emissions are below 0.55 lb/million Btu and 0.3 lb/million Btu, respectively.[2] Existing EPA emission levels are 1.2 lb/million Btu for sulfur and 0.7 lb/million Btu for NO_x. Recent experimental evidence indicates that NO_x emission may be virtually eliminated; thus MHD will be within the recently proposed EPA standard of 0.5 lb/million Btu. These reductions below EPA emission standards occur without preprocessing of coal and without use of expensive stack gas clean-up systems.

Thermal pollution also is reduced in the MHD process. A small percentage of available heat/unit of fuel input is wasted to the heat sink because the cycle is more efficient. Thus, where thermal pollution of river and coastal waters is a problem, MHD has an advantage over conventional systems. In addition, the reduction in water consumption for cooling towers in regions of scarce water has the beneficial effect of preventing water extraction from rivers and streams to levels that endanger their ecology.

The beneficial environmental effects of MHD have not been proved commercially. However, promising experimental results, predicted efficiencies, and theoretical studies demonstrate the potential of MHD as an environmentally benign alternative energy technology.

ECONOMICS

If the technical problems of MHD are solved, the economic benefits can be significant. The ECAS report concluded, for example, that a combined MHD/steam generating power plant would reduce the cost/kWh of a conventional coal-fired plant by 13.5 percent. (The study concentrated on baseload power plant systems and assumed increasing fuel prices. It is not clear whether all the factors included in a total systems cost were considered.) Since the ECAS report was published in 1975, MHD technology has improved substantially, which may increase its economic advantages.

The reported economic saving of approximately 5 mill/kWh for coal-fired power plants appears small, but the total impact on the economy is substantial. In 1977, coal-fired plants produced 985,219 million kWh of electricity.[9] If all coal-fired plants used MHD and 5 mill/kWh were saved, the total savings to the economy would be about $4.9 billion. While not all plants would use MHD, the magnitude of the total effect on the economy from such an apparently small decrease in cost/kWh is illustrated by such a calculation.

If MHD can be applied to the utility industry, there will be an incentive to substitute coal, a more abundant resource, for petroleum, resulting in a substantial effect on the total economy. In 1977, almost 17 percent of electricity was produced using petroleum.[9] As petroleum increases in price, the substitution of coal has obvious economic advantages. Also, the switch from petroleum to coal would reduce imports with the resulting beneficial effects on the balance of payments. An additional benefit is less dependence on foreign oil and the concomitant reduction of the economic impacts of potential supply interruptions. MHD's environmental advantages may result in further savings, intensifying the above effects.

While MHD appears to be an economical energy technology, the economics must be verified in an industrial environment. The cost relationship between MHD's environmental advantages and downstream pollution control equipment must also be studied. Another area for further study is the applicability of MHD to energy-intensive industries that require a mix of electrical and thermal power (allowing cogeneration). Such industries (aluminum, steel, copper, other primary metals, chlorine, and some other chemicals) account for about 10 percent of U.S. energy consumption. An MHD topping cycle could be used to produce DC current for industrial use, while the bottoming cycle produces AC power for direct use (in-plant utilities) and sale to other consumers. Generated steam for plant use and other consumers is an added possibility. Such multiplant concepts do not have to be widespread to have a significant effect on U.S. energy consumption; six energy-intensive industries account for about 70 percent of the nation's industrial thermal energy consumption, and cogeneration may reduce system fuel requirements by 10 to 30 percent.[10] MHD commercialization may result in significant economic benefits as it is applied throughout the economy in such multiple uses.

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17. ENERGY CONVERSION TECHNOLOGY

Energy sources may be used directly as fuel to provide heat and mechanical power or may be converted to electricity. Earlier chapters of this *Energy Fact Book* provided information on energy sources, discussing their availability and the forms in which they are used. Many new energy conversion technologies using energy sources little used heretofore (such as wind and solar power) or using the primary energy sources more efficiently (for example, fuel cells and magnetohydrodynamics) also were described. This chapter summarizes conventional technologies for converting the potential energy of fuels into useful work and describes methods for storing the energy generated. Recent developments to improve the efficiencies of these energy conversion technologies also are summarized. Overall thermal efficiencies of selected energy conversion systems are listed in Table 17-1, which shows that some conversion devices or systems transform energy from one form to another at an efficiency approaching 100 percent, while others may have a much lower theoretical limiting efficiency.

HEAT ENGINES[1-4]

The simplest and by far the most widely used method of converting chemical or nuclear energy into useful work is by means of a heat engine. The transformation of the energy released as heat during nuclear fission or the combustion of fuel into mechanical work is accomplished by increasing the thermal energy of a working fluid at elevated pressure confined within the engine and then allowing the working fluid to produce mechanical work during a restrained expansion process. Any such engine must carry the working fluid through a sequence of thermodynamic states to convert the thermal energy to useful work. This sequence of states forms what is called the thermodynamic cycle on which the heat engine operates and by which it is described. This cycle affects the engine's power output, fuel consumption, and pollutant emission characteristics.

In addition to its thermodynamic cycle, a heat engine may also be classified as an open or closed cycle, internal or external combustion, and intermittent or continuous combustion engine. In an open-cycle machine, the working fluid is inducted into the engine from the surroundings; is passed through the engine, therein absorbing heat and producing work; and is then exhausted to the surroundings. Conversely, in a closed-cycle machine, the working fluid is completely contained within the engine and is recirculated to repeat the thermodynamic cycle. The heat addition and rejection processes usually are accomplished with heat exchangers.

The distinction between internal and external combustion engines lies in the nature of the heat addition process. Heat addition in an internal combustion engine is accomplished inside the engine by combustion of fuel within a compressed volume; the combustion prod-

Table 17-1. ENERGY CONVERSION EFFICIENCIES

Conversion System	Overall Thermal Efficiency (Percent)	Comments
Heat engines[a]		
Carnot cycle	—	Solely a function of temperature at which heat is added and rejected.
Otto cycle	20-35	Increases with compression ratio.
Diesel cycle	25-40	Increases with compression ratio, but also varies with amount of heat added.
Brayton cycle	34-40	Controlled by turbine inlet temperatures and pressure ratios.
Stirling cycle	34-47	Theoretically, equivalent to that of Carnot cycle.
Rankine cycle	25-31	Increases with temperature.
Thermal energy systems		
Heating by direct combustion[b]		
Hot air		
Coal-fired	55	Depends on equipment maintenance and adjustment. Efficiency for commercial establishments is 70 percent.
Gas-fired	40-80	Depends on operating practices and equipment adjustments.
Petroleum-fired	40-80	Depends on operating practices and equipment adjustments.
Hot water		
Coal-fired	15	Efficiency for commercial establishments is about 70 percent. Probable error is less than 25 percent.
Gas-fired	64	Probable error is less than 25 percent.
Petroleum-fired	50	Probable error is less than 25 percent.
Electric heating	95	30 percent, if electricity generation efficiency is included.
Refrigeration cycles	50	Average value for electric refrigeration devices.
Heat pumps	60-75	About 50 percent less in winter.
Electric power generation		
Steam turbines	35-40	Limited by combination of working fluid properties and operating temperatures of materials.
Gas turbines	27-34	Function of compressor and turbine efficiencies, ambient air temperature, nozzle inlet temperature, and type of cycle used.
Diesel engines	25-40	Depends on kWh produced.
Nuclear fission	30-42	Depends on nuclear reactor type.
Hydroelectric	75-80	Actual efficiency of most installations.
Fuel cells	35-75	Function of cell type and plant size.
Magnetohydrodynamics	46-50	Open-cycle plasma systems operating as topping system on conventional steam plant.
Advanced combined-cycle systems	50-60	Closed-cycle systems are less efficient than open-cycle systems.
Cogeneration systems		
Steam turbine topping systems	65-85	Requires 4,000 to 6,000 Btu of fuel for each kWh produced.
Gas turbine topping systems	53-62	Requires 5,500 to 6,500 Btu of fuel for each kWh produced.
Diesel engine topping systems	49-53	Requires 6,500 to 7,000 Btu of fuel for each kWh produced.
Steam bottoming systems	14-36	Operates at 150 to 535°C.
Organic Rankine bottoming systems	~13	Operates at 90 to 170°C.

[a]The thermal efficiency of heat engines is expressed quantitatively as the ratio of the output of energy in the form of useful work to the input of energy in the form of heat from the high-temperature source.

[b]Values shown are residential.

Sources: The Science and Public Policy Program, *Energy Alternatives: A Comparative Analysis* (Norman, OK: University of Oklahoma, 1975); Jet Propulsion Laboratory and California Institute of Technology, "Should We Have a New Engine? An Automobile Power Systems Evaluation," Volume I, JPL SP 43-17, August 1975; *Encyclopedia of Energy* (New York: McGraw-Hill Book Company, 1976); and D. M. Considine, ed., *Energy Technology Handbook* (New York: McGraw-Hill Book Company, 1977).

ucts also act as the working fluid. In an external combustion engine, the engine working fluid passes through a heat exchanger to receive heat from the combustion process carried on outside the engine.

The combustion process in heat engines may occur continuously or intermittently depending on the design of the engine. A continuous combustion engine has a separate and

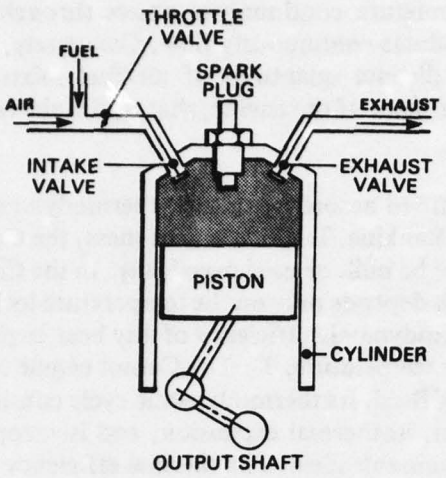
distinct combustion device in which the air/fuel mixture continuously passes through a region of sustained combustion from which the products continuously flow. Conversely, in an intermittent combustion engine, specific and distinct quantities of air/fuel mixture repeatedly are ignited and burned in the combustion space of the engine; that is, the air/fuel mixture is burned in successive batches.

There are six basic types of heat engines, identified according to their thermodynamic cycles: Carnot, Otto, Diesel, Brayton, Stirling, and Rankine. The first one of these, the Carnot engine, is strictly a theoretical engine that cannot be built or used practically. In the Carnot cycle, the efficiency of converting heat into work depends only on the temperature levels involved; this cycle has the maximum possible thermodynamic efficiency of any heat engine operating between a high temperature, T_1, and a low temperature, T_2. The Carnot engine is a closed-cycle engine using an ideal gas as the working fluid. Its thermodynamic cycle consists of isentropic compression, isothermal heat addition, isothermal expansion, and isentropic heat rejection. All processes are reversible, an unattainable ideal. The thermal efficiency of the Carnot cycle is solely a function of the temperature at which heat is added (T_1) and the temperature at which heat is rejected (T_2). This efficiency, η, is stated as $\eta = (T_1 - T_2)/T_1$ with T expressed as the absolute thermodynamic temperature. All heat engines are compared to the ideal, or Carnot, engine to determine their relative thermodynamic efficiency.

The Otto engine is an open-cycle, intermittent, internal combustion engine with spark ignition employing either uniform (homogeneous) fuel charge or stratified (heterogeneous) fuel charge. Its ideal thermodynamic cycle consists of isentropic compression, constant volume heat addition, isentropic expansion, and constant volume heat rejection. The maximum feasible thermodynamic efficiency of the Otto engine is limited by the highest compression ratio that can be used in practice (about 8:1 to 10:1). Engines with compression ratios of about 8:1 generally have indicated thermal efficiencies ranging from 30 to 34 percent; with a 10:1 ratio, the efficiency increases only a few percent. The Otto engine is widely used in automobiles, motorcycles, buses, light trucks, and small aircraft, as well as small stationary emergency electric generators. The conventional Otto cycle spark-ignition intermittent combustion engine, shown in Figure 17-1, burns a uniform mixture of air and fuel usually provided by a carburetor. The stratified-charge Otto cycle (see Figure 17-2) is different, in that a rich fuel-air charge is used to start burning in a small zone, and burning then spreads through the rest of the mixture, which is fuel lean. Hence, the name "stratified" charge.

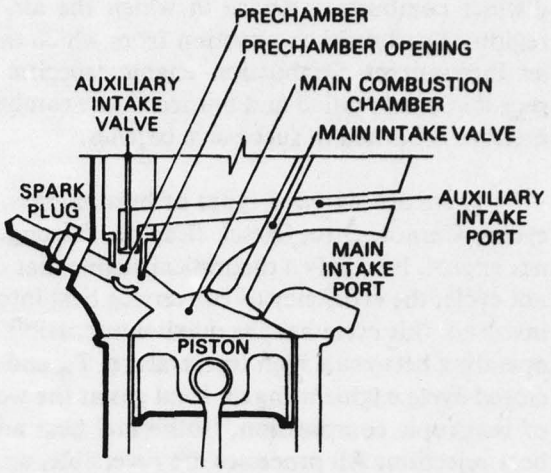
Most Otto-cycle engines are of the reciprocating type, although some rotary (Wankel) designs are in production. Also, several second-generation rotary-combustion engines are under development, including the Wankel two-lobe housing, Isuzu three-lobe, Variant four-lobe, Renault-Rambler five-lobe, and gear-in-gear n-lobe housings. Four entirely different rotary engine concepts being investigated are the Kauertz, Tschudi, Kal-Pac, and Mallory rotary engines.

The Diesel engine is an open-cycle, intermittent, internal combustion engine with compression ignition. Its ideal thermodynamic cycle consists of isentropic compression, limited pressure heat addition, isentropic expansion, and constant volume heat rejection. The Diesel engine, originally used in larger trucks, railroad engines, and ship engines, now is be-



Source: Jet Propulsion Laboratory and California Institute of Technology, "Should We Have a New Engine? An Automobile Power Systems Evaluation," Volume I, JPL SP 43-17, August 1975.

Figure 17-1. UNIFORM-CHARGE OTTO CONVENTIONAL ENGINE



Source: Jet Propulsion Laboratory and California Institute of Technology, "Should We Have a New Engine? An Automobile Power Systems Evaluation," Volume I, JPL SP 43-17, August 1975.

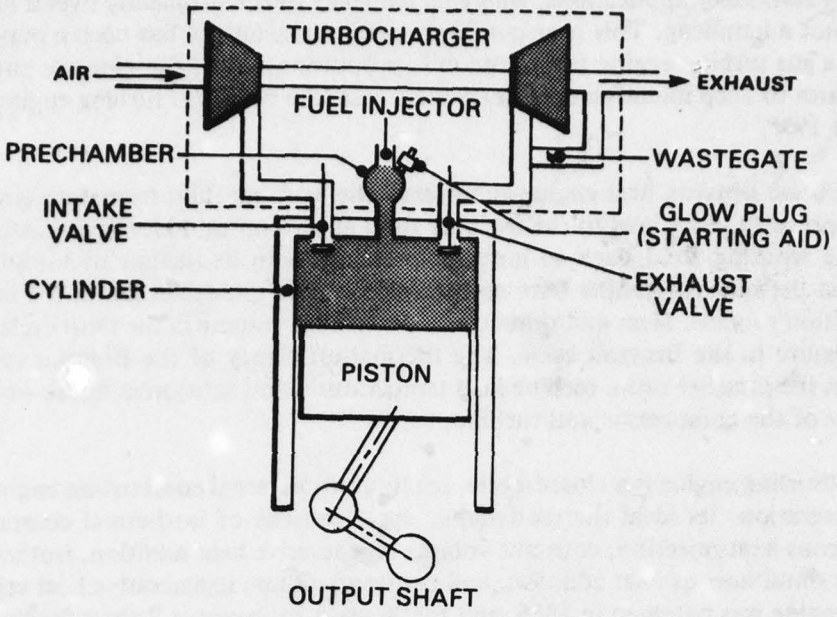
Figure 17-2. STRATIFIED-CHARGE OTTO ENGINE (HONDA CVCC ENGINE)

ing used increasingly in automobile engines, including the small sizes. Before the advent of the gas turbine, all large stationary motors, as in electrical generating plants, were diesel.

Diesel engines differ from Otto engines in the use of high compression generated heat to cause self ignition in lieu of spark ignition (see Figure 17-3). Such self ignition requires nearly twice the compression ratios needed for Otto cycle engines, and therefore the engines are considerably heavier than comparable Otto engines. The fuel ignition properties are exactly opposite to those desired for an Otto cycle, so that a good diesel fuel is automatically a poor Otto fuel and vice versa. The efficiency and emissions characteristics of Diesel engines are coupled directly to the compression-ignition combustion process. A Diesel engine can operate at a higher efficiency than an Otto engine because fuel requirements limit the Otto engine to a compression ratio of about 10, whereas a Diesel engine can operate at a compression ratio of about 15. In an actual engine with a given compression ratio, the Otto engine has the higher efficiency.

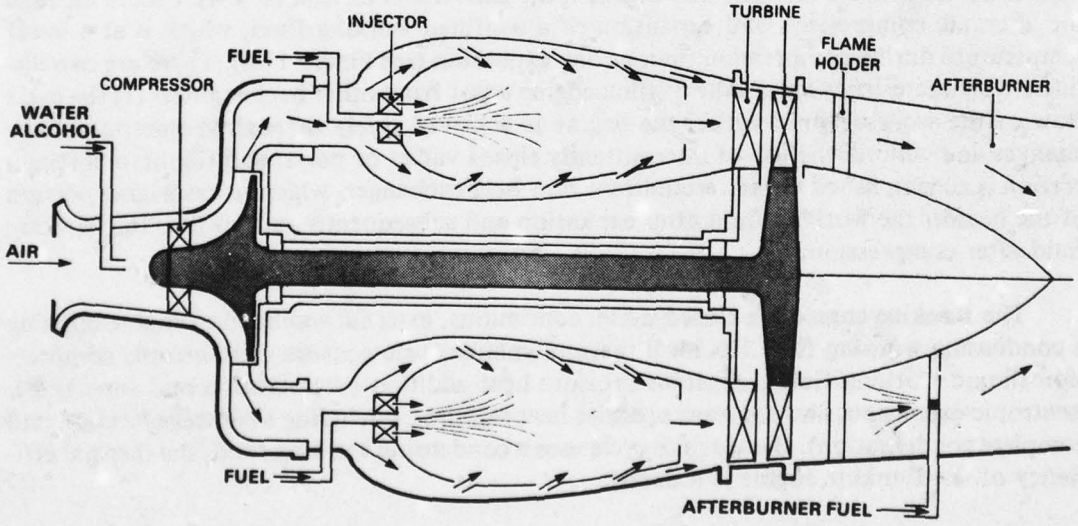
The typical Brayton engine is an open-cycle, continuous, internal combustion engine with or without exhaust heat recovery, that is, thermal regeneration. Its ideal thermodynamic cycle consists of isentropic compression, constant pressure heat addition (can be partly regenerative), isentropic expansion, and constant pressure heat rejection (can be partly regenerative). Brayton engines may also be configured as closed-cycle machines. Air is the medium for an open-cycle Brayton engine, whereas an inert gas is used as the working fluid in a closed-cycle engine.

The Brayton-cycle engine is virtually synonymous with a gas turbine engine (see Figure 17-4). At present, the gas turbine engine is the engine of choice in large commercial aircraft



Source: Jet Propulsion Laboratory and California Institute of Technology, "Should We Have a New Engine? An Automobile Power Systems Evaluation," Volume I, JPL SP 43-17, August 1975.

Figure 17-3. DIESEL ENGINE (TURBOCHARGED)



Source: Ethyl Corporation, "Aviation Fuels and Their Effects on Engine Performance," 1951.

Figure 17-4. TURBO-JET ENGINE (BRAYTON CYCLE)

and many stationary applications, where its tendency to run efficiently over a narrow speed range is not a handicap. This near-constant-speed characteristic has been a major deterrent to using a gas turbine engine for automobile propulsion, but the engine has enough attractive features to keep manufacturers interested; test cars using gas turbine engines have been run since 1956.

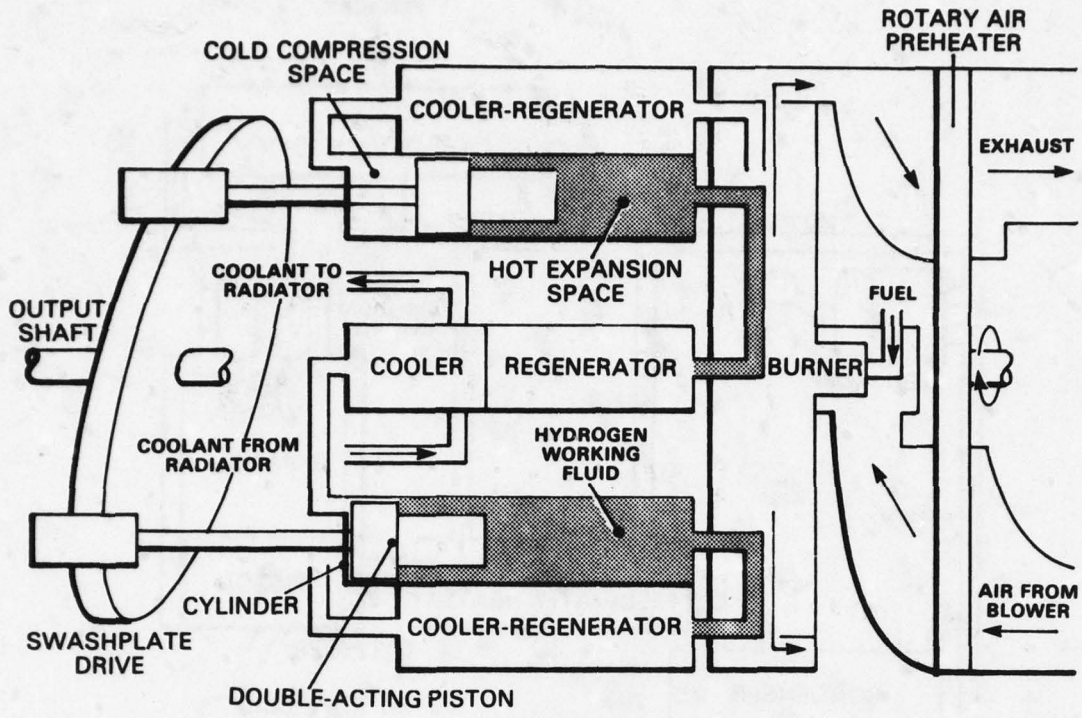
The basic Brayton heat engine compresses the working fluid from ambient pressure to elevated pressure, adds heat to the working fluid at the constant elevated pressure, then expands the working fluid back to ambient pressure, with extraction of useful work. The distinction between the simple Otto and the simple Brayton cycles lies in the nature of the heat addition process. Heat addition occurs at constant volume in the Otto cycle and at constant pressure in the Brayton cycle. The thermal efficiency of the Brayton cycle depends mainly on the pressure ratio, turbine inlet temperature, and subsystem losses—especially the efficiency of the compressor and turbine.

The Stirling engine is a closed-cycle, continuous, external combustion engine with thermal regeneration. Its ideal thermodynamic cycle consists of isothermal compression with simultaneous heat rejection, constant volume regenerative heat addition, isothermal expansion with simultaneous heat addition, and constant volume regenerative heat rejection. The Stirling engine was patented in 1816, and for 30 years its inventor Robert Stirling developed it with air as the working fluid. The complexity of its design precluded its adoption when fuel was cheap and pollution not a matter for concern. The Stirling engine is again under development both in the United States and in Europe because of its potentially high thermal efficiency (theoretically, its efficiency could equal that of the Carnot engine) and low pollutant emissions. Because of the extremely complex design required, however, it is still in the developmental stage.

A Stirling engine is a machine in which the conversion of heat to work occurs through the alternate compression and expansion of a confined working fluid, which is at a lower temperature during compression than during expansion (see Figure 17-5). There are two distinctive characteristics setting the Stirling engine apart from other heat engines: (1) the cycle flow of the working fluid within the engine is achieved solely through geometric volume changes and without the use of intermittently closed valves or ports; and (2) thermal regeneration is accomplished via an intermittent flow heat exchanger, which stores a large portion of the heat of the working fluid after expansion and subsequently returns it to the working fluid after compression.

The Rankine engine is a closed-cycle, continuous, external combustion engine utilizing a condensing working fluid. Its ideal thermodynamic cycle consists of isentropic compression (liquid working fluid), constant pressure heat addition (vaporization and superheat), isentropic expansion, and constant pressure heat rejection (including slight regeneration and complete condensation). Because the cycle uses a condensing working fluid, the thermal efficiency of the Rankine engine is reduced.

The steam engine, whether reciprocating or turbine drive, is based on the Rankine cycle. The steam engine and Rankine cycle engine are practically synonymous today. Heat from the combustion of fuel in air is transferred to water, first in a boiler to vaporize it to



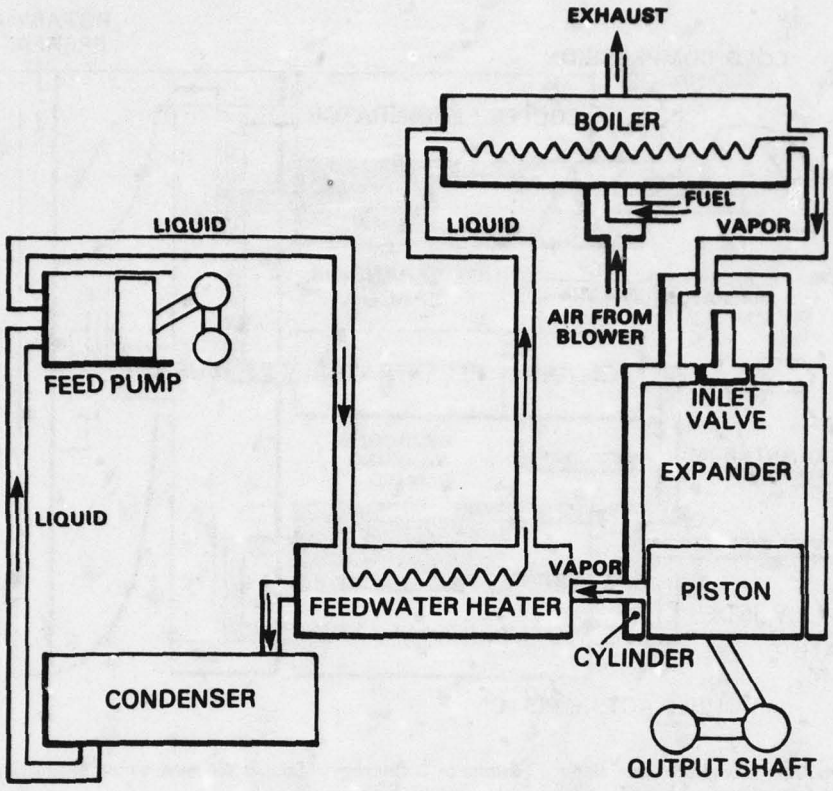
Source: Jet Propulsion Laboratory and California Institute of Technology, "Should We Have a New Engine? An Automobile Power Systems Evaluation," Volume I, JPL SP 43-17, August 1975.

Figure 17-5. STIRLING ENGINE

steam at high pressure, and then in a heat exchanger to superheat the steam. The steam on expanding produces useful work; the resulting low-pressure steam is condensed and pumped back into the boiler. A typical Rankine cycle engine is shown in Figure 17-6.

THERMAL ENERGY SYSTEMS[3-5]

Heat is transferred in three ways: conduction, convection, and radiation. To obtain the desired heat flow, thermal energy systems for heating and cooling (refrigeration) are designed using a knowledge of the principles governing these three methods of heat transfer. Several systems are in common use, and many more are under development. The energy required for heating or cooling can come from a variety of sources. The simplest and most common form of heating involves circulating hot air, hot water, or steam. The air or water is heated by a direct combustion furnace that burns fossil fuel with air, or by heaters that obtain heat from an electric current passing through a resistance. Cooling is accomplished using air or water cooled by evaporation, mechanical refrigeration, or absorption refrigeration. When both cooling and heating are required (at different times) use of a heat pump can be advantageous.



Source: Jet Propulsion Laboratory and California Institute of Technology, "Should We Have a New Engine? An Automobile Power Systems Evaluation," Volume I, JPL SP 43-17, August 1975.

Figure 17-6. RANKINE ENGINE (RECIPROCATING)

Heating by Direct Combustion

A hot air system comprises a direct-fired furnace surrounded by a space through which the air to be heated circulates. Although oil and gas are the most commonly used fuels today, furnaces can be designed to burn solid fuels such as coal or wood as they did in the past. Air circulation can be achieved by natural convection, but forced-draft systems are more common in commercial facilities as well as residential ones.

A hot water system, in contrast to a hot air system, can be used to heat several buildings. An individual building may have a direct-fired furnace to heat water, which circulates through the radiators by gravity or forced circulation. Central heating is achieved when several buildings or groups of buildings are tied together by a network of piping for circulating hot water from a single heating plant. Firing efficiencies depend on such factors as fuel type and boiler and plant design, and usually range from 85 to 93 percent in large central heating plants. For smaller central heating plants, efficiencies range from 60 to 70 percent. Where air conditioning is required, the central plant may be used to provide the energy

source for the summer cooling refrigeration plant. Central plants using hot water or steam are suitable for this purpose.

Space heating with steam now is used only in existing older systems or where there is a specific requirement for high-pressure steam. Except for electric power generation, most steam produced is used for industrial process heat or absorption refrigeration.

Electric Heating

Electric heat can be produced by resistance heaters, dielectric heaters, induction heaters, and electric-arc heating. Heat can be transferred to the surroundings by conduction and by radiation. Resistance heaters are also used to heat water in a small finned-tube radiator, which acts like a hot water radiator in a room.

Radiant heat is emitted from panels installed in floors, walls, or ceilings of spaces to be heated. These panels may be heated either by hot water flowing through tubes embedded in the panels or by an electric current passing through a resistance located in the panel. Fuel consumption records show that panel heating systems save 30 to 50 percent of the fuel costs of ordinary heating systems.

Evaporative Cooling

For evaporative cooling, the warm, dry or unsaturated air is mixed with water. Some of the sensible heat of the air is tranferred to the water causing the water to evaporate and the air temperature to drop. Evaporative cooling frequently is carried out by blowing relatively dry air through a wet mat.

The most important form of air cooling is by finned coils which circulate a cold fluid or a cold boiling refrigerant. In most applications, the finned surfaces become wet as condensation occurs simultaneously with sensible cooling. Usually the required amount of dehumidification determines the temperature at which the surface is maintained. Where this results in air that is colder than required, the air is reheated to the proper temperature. Nearly all window air conditioners operate on this principle, as do many larger commercial units.

Refrigeration Cycles

In the refrigeration cycle, a vapor, called the refrigerant (such as Freon), is compressed, condensed by cooling, then expanded back to a vapor. In expanding, the refrigerant absorbs heat from its surrounding space, thus cooling that space. After the refrigerant absorbs heat from the surroundings, it is compressed and the cycle repeated. Compression raises the temperature of the refrigerant above that of its natural surroundings so that it can be cooled in a heat exchanger by giving up heat to air or water at the temperature of the surroundings. Expansion lowers the refrigerant temperature below the temperature that is to be produced inside the cold compartment or refrigerator. The sequence of processes performed by the refrigerant constitutes the refrigeration cycle. When the refrigerant is compressed mechanically, the refrigerative action is called mechanical refrigeration.

Other methods by which cooling can be produced include the noncyclic melting of ice, or the evaporation of volatile liquids as in local anesthetics; the Joule-Thomson effect, used to liquefy gases; the reverse Peltier effect, which produces heat flow from the cold to the hot junction of a bimetallic thermocouple when an external electromotive force is imposed; and the paramagnetic effect, used to reach extremely low temperatures. However, large-scale refrigeration or cooling generally calls for mechanical refrigeration acting in a closed system.

Absorption refrigeration often is used where the cost of electric energy is high and that of heat is inexpensive. Currently, absorption refrigeration systems mainly use water as the refrigerant and lithium bromide as the absorbent. (Ammonia systems are available but are not as widely used because of their complexity and high initial cost.) Water-lithium bromide absorption units use two basic factors to produce a refrigeration effect: water will boil, and flash cool itself, at low temperatures when it is maintained at a high vacuum; and certain substances, such as a salt, will absorb water vapor. The absorption refrigeration system contains five main components: generator, condenser, evaporator, absorber, and heat exchanger.

Heat is supplied to the generator by combusting gas to produce low-pressure steam. In the evaporator, the refrigerant (water) is cooled indirectly by spraying water over the evaporator tubes that contain the refrigerant. The water vaporized is absorbed by a strong salt solution (generally lithium bromide) in the absorber. The resulting weak solution is pumped through the heat exchanger to the generator where the absorbed water is boiled off to concentrate the salt solution before it reenters the absorber. The water boiled off in the generator is condensed to a liquid in the condenser, and the condensate is returned to the evaporator. The total heat load—the refrigeration load, the heat of dilution, cooling of condensed water, and cooling of the salt solution—is transferred to cooling water circulated from a cooling tower.

Heat Pumps

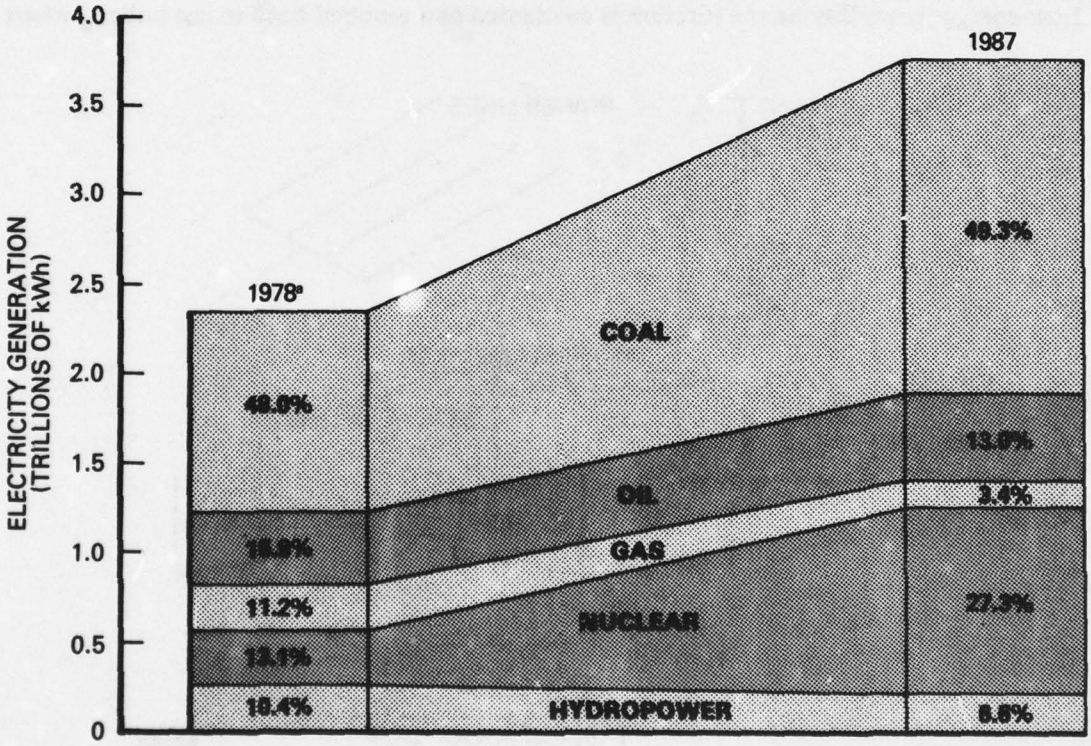
A heat pump is a system that can pump heat either out of or into structures to provide air conditioning or heating. Any refrigeration system, including a household refrigerator, is a heat pump, because heat is removed from a contained, insulated structure at a lower temperature and exhausted, or pumped, at a high temperature into a relatively open air space such as the interior of a house or other building—in some cases, the external atmosphere itself. Heat pumps are much more efficient than resistance heaters but they are most efficient when they operate over a relatively small temperature difference. Types of heat pumps include air-to-air, water-to-air, and water-to-water systems, depending on the fluids that are heated and cooled.

An air-to-air system has a valve that reverses the flow of the refrigerant (refrigeration units) so that the indoor coil acts as an evaporator on the cooling cycle and as a condenser on the heating cycle. In the water-to-air heat pump, the indoor coil is a refrigerant condenser or evaporator (for heating or cooling) but a water-to-refrigerant heat exchanger replaces the outdoor coil. The water-to-water type features both the condenser and the evaporator as water-to-refrigerant heat exchangers, switching the water flows instead of the refrigerant flows. Hence, when cooling is required in a space, chilled water leaving the evaporator is

directed to the space-conditioning equipment; when heating is required, warm water leaving the condenser is directed to this equipment. A typical heating coefficient of performance for heat pumps is 4—that is, 1 Btu of work input will yield an additional 3 Btu of heat (a total of 4 Btu) to the space. Thus, electric power consumption and hence the operating cost will be 25 percent of that required by a straight electric resistance heating system. The coefficient of performance for cooling is one less than that for heating because the heat of the compression work required must be rejected rather than added to the conditioned space. Also, the greater the spread between the evaporating and condensing temperatures, the poorer the performance of both heating and cooling cycles.

ELECTRIC POWER GENERATION SYSTEMS

Electric power can be generated using a variety of energy sources, principally, coal, oil, gas, nuclear, and hydropower (see Figure 17-7). About 76 percent of the electricity in the United States is produced in conventional power generation systems using coal, oil, or



[a]An additional 0.6 percent (less 0.2 percent net pump storage requirement) is generated by geothermal or other unconventional energy sources.

Source: *8th Annual Review of Overall Reliability and Adequacy of the North American Bulk Power Systems* (Princeton, NJ: National Electric Reliability Council, 1978).

Figure 17-7. ELECTRICITY GENERATION BY PRINCIPAL ENERGY SOURCE, CONTIGUOUS UNITED STATES

gas—74 percent in steam turbines and 2 percent in gas turbines or diesel engines. (Gas turbines and diesel engines often are used for standby power generation during periods of peak loading on the utilities grid or of unscheduled outages. This type of equipment may also be provided by the end-user, either for emergencies or, in the case of remote or inaccessible locations, in place of utility-supplied electrical power.) Another 13 percent of the electricity in the United States is produced in nuclear power plants, and about 10 percent in hydroelectric plants. Less than 1 percent is generated using nonconventional sources of energy, such as geothermal, solar, wind, or ocean energy. (Nuclear and hydroelectric power generation systems as well as nonconventional sources of energy are discussed in detail in other chapters of this *Energy Fact Book*.)

Steam Turbines[3,6-10]

At the end of 1977, there was a total of 951 steam electric plants in the United States, and 320 more probably will be built during the next decade. Figure 17-8 shows a typical steam plant for the generation of electricity. Fuel is burned in large boilers to provide high-pressure steam to drive turbines, which in turn drive generators to provide electric power. Low-energy steam leaving the turbines is condensed and pumped back to the boilers, where

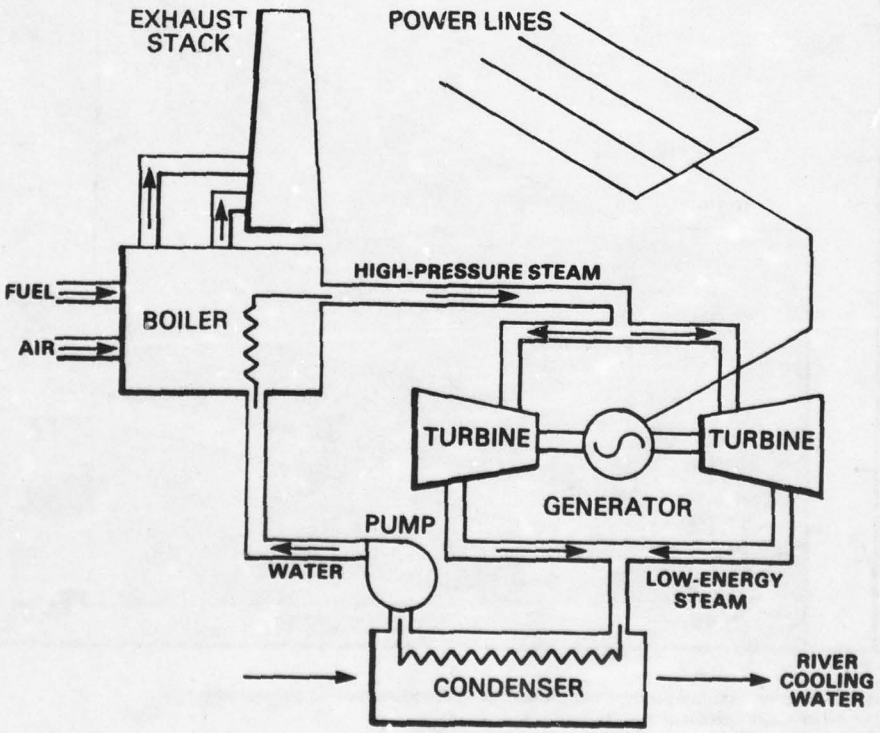


Figure 17-8. TYPICAL STEAM PLANT FOR POWER GENERATION

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it is heated into steam again; the cycle is then repeated. Condensing systems can use river water, a cooling pond, or wet or dry cooling towers to dispose of waste heat. (Waste heat also may be used for cogeneration purposes as discussed later in this chapter.) Exhausted combustion gases are treated, if necessary, to reduce particulate and sulfur oxide emissions.

Steam plants can be fueled with coal, oil, or gas. Government regulatory policies have a major influence on the selection of fuels for steam electric plants. Gas and oil have lower sulfur and ash contents than coal and thereby avoid sulfur oxide and particulate emission problems. Government energy policy, however, strongly encourages the use of coal, which is in more plentiful domestic supply. Therefore, many plants now burning these fuels are converting their boilers to coal burning. (A number of plants now burning oil and gas have burned coal in the past and have facilities for conversion depending on fuel availability, costs, and environmental restrictions.) Converting oil and gas burning steam electric plants to coal involves extensive retrofitting of handling and storage facilities, boiler design, ash and other solid waste disposal, and flue gas treatment facilities. The cost of an air pollution control system alone may be as much as 50 to 60 percent of the apparent conversion cost. Hidden environmental costs, such as treatment for coal pile and ash pond leachate and runoff, may constitute another 12 to 15 percent of the conversion cost.

Boiler sizes for steam electric power plants in the United States range from less than 1,000 to about 7,000 lb/hour, and most (about 65 percent) range from 3,500 to 5,500 lb/hour. Furnaces in today's units generally are larger than those in comparable boilers built only a few years ago, allowing greater fuel flexibility. Turbines used in U.S. steam electric plants are rated from 100 to 900 MW, with about 40 percent rated from 500 to 699 MW. The current average thermal efficiency of steam electric plants is about 35 percent, using 3,500 psi and 540°C maximum steam conditions as practical design limits. In 1977, steam electric plants required 10,450 Btu of fuel value to produce 1 kWh of electricity. Steam turbines have achieved up to 40 percent thermal efficiency using initial steam conditions of 6,000 psi and 650°C, but the cost of the special metals required at these conditions has not been justified by the small efficiency gains.

Since the basic technology for steam electric power plants is well established, development efforts are focused on boiler or turbine design improvement, primarily optimum, cost-effective unit designs and sizes. In addition, the electric-utility industry is making an effort to improve the availability and reliability of its power plants. To be reliable, efficient, and capable of delivering full output, generating facilities are taken out of service from time to time for maintenance. Maintenance is scheduled for periods when demand for electricity is low.

Another area for study involves developing economical ways to meet federal emission standards. Utility power plants are responsible for about 14 percent of the total air pollutants in the United States—primarily sulfur dioxide, particulates, and nitrogen oxides. The Environmental Protection Agency has established a primary standard for sulfur dioxide with an annual mean concentration of 0.03 ppm and a 24 hour maximum of 0.14 ppm not to be exceeded more than once a year. A secondary standard limits the 3 hour maximum concentration to 0.5 ppm, not to be exceeded more than once a year. In addition, new source performance standards restrict coal-fired boilers with capacities above 25 MW to a max-

imum 2 hour sulfur dioxide emission of 1.2 lb/million Btu heat input. Even more stringent standards are being proposed. To meet federal emission limitations, the principal options for coal-fired electric power plants are coal cleaning prior to burning, control of emissions in the stack gas, and control during combustion (fluidized-bed combustion). These techniques and their environmental impacts are discussed in Chapter 4.

In addition to air pollution concerns, steam electric power plants require large quantities of water for cooling. The discharge of water into surface water bodies produces both thermal and chemical pollution, which may have deleterious effects on the environment. Furthermore, the availability of water may be limited by the physical supplies, alternative uses, or legal and administrative controls.

Environmental concern extends not only to air and water pollution, but also to esthetic and economic objections to the use of choice land for power plants and for transmission lines. The combination of environmental concerns for steam-electric power plants has had, and will continue to have, major impact on both the availability and economics of electric power generation.

Construction costs for a steam electric plant with two 575 MW units, without scrubbers, are estimated to be about $484/kW. A plant with two 550 MW units, with flue-gas scrubbers, would cost about $638/kW. For comparison, the construction cost of a nuclear generating plant comprising two 1,200 MW nuclear units would be about $692/kW. (The cost estimates, in 1977 dollars, were made in 1978, and reflect a 7 percent annual allowance for funds used during construction.)

Estimated total busbar generating costs for future electric power plants are shown in Table 17-2. Fuel costs and carrying charges (amortization of construction investment) are the major costs, with operation and maintenance comprising only 1 to 5 mill/kWh of the total cost of 35 to 43 mill/kWh. The significant influence of fuel costs is best illustrated by

Table 17-2. ESTIMATED TOTAL BUSBAR GENERATING COSTS FOR FUTURE PLANTS, 1977 DOLLARS

Plant Type	Cost (mill/kWh)			
	Fuel	Operation and Maintenance	Carrying Charges	Total
Nuclear	7	2	26	36
High-sulfur coal with scrubbers	13	5	24	42
Low-sulfur coal				
Without scrubbers[a]	15[b]	2	18	35
With scrubbers	16	3	24	43
Oil without scrubbers	26	1	15	42

[a]Not feasible under existing emission control standards.

[b]Higher fuel cost in scrubber case is for additional fuel to make up for inefficiencies in the scrubber operation.

Source: A D. Rossin and T. A. Rieck, "Economics of Nuclear Power," *Science*, Vol. 201, August 1978.

the high cost of oil, while the significant impact of environmental emission controls is shown for the low-sulfur coal options.

Gas Turbines[3,11]

Gas turbines generate about 1 percent of the electrical power used in the United States. They are classified by the physical arrangement of the component parts and include single shaft, two shaft, regenerative (heat exchanger is used to recover exhaust losses and to heat air to the combustor), intercooled (heat removed between compressor stages), and reheat (heat added between turbine stages) systems. Sizes can range up to 300 MW. Starting power requirements of an unloaded gas turbine range between 5 and 10 percent of the full-load speed; two-shaft turbines require slightly more starting power than single-shaft machines. A wide variety of fuels can be used in gas turbines. The major fuel requirements are that the fuel does not form ashes, which will deposit on the blades and interfere with operation, and does not contain dust, which will erode the blades. Commonly used fuels include natural and refinery gas, blast-furnace gas, and fuel oils (including heavy residuals). Gases derived from coal and other nontraditional sources also are being used increasingly in gas turbines. Gas turbines have been installed as standby generation sets in industrial plants, communication and computer centers, hospitals, apartment and office buildings, hotels, motels, schools, and other public facilities. Gas turbine generator sets also are used extensively in offshore drilling exploration, construction projects, military operations, and emergency activities.

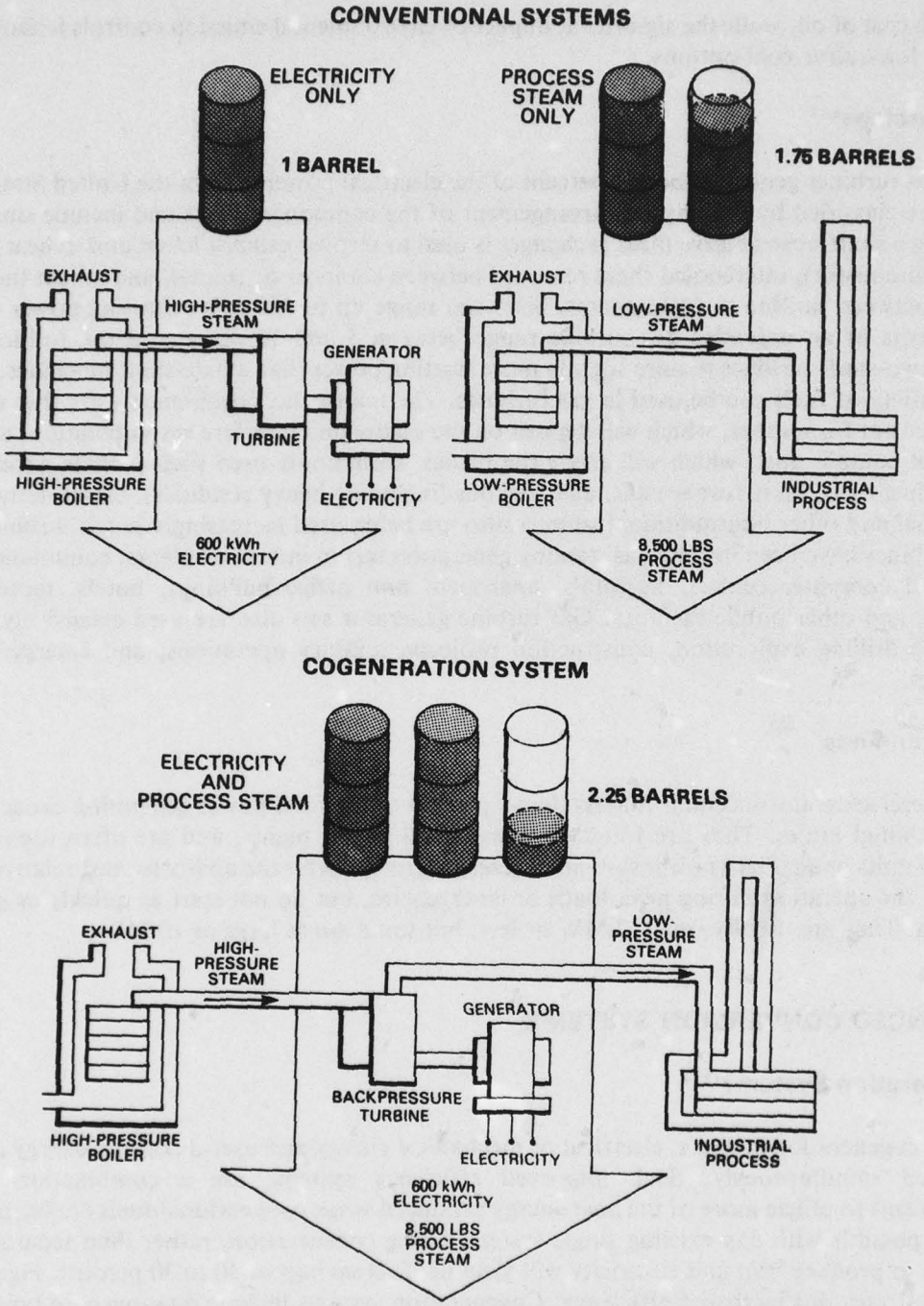
Diesel Engines[3]

Diesel generators account for less than 1 percent of the total power generation capacity in the United States. They are found in many small power plants, and are often used as standby units or auxiliary power systems. Diesel generators offer the ability to start relatively quickly for operation during peak loads or emergencies, but do not start as quickly as gas turbines. They are usually small, 2 MW or less, but some are as large as 10 MW.

ADVANCED CONVERSION SYSTEMS

Cogeneration Systems[12-14]

In cogeneration systems, electrical or mechanical energy and useful thermal energy are produced simultaneously. Such improved efficiency systems use a combination of mechanisms to utilize more of the heat energy produced when conventional fuels are burned than is possible with any existing single system. Using cogeneration, rather than separate, systems to produce heat and electricity will yield net fuel savings of 10 to 30 percent. Figure 17-9 illustrates this increased efficiency. Cogeneration systems include dual-purpose power plants, waste heat utilization systems, certain types of district heating systems, and total energy systems. Such systems have been applied since the late 1880s and, in the United States, have been used much more widely in the past than they are today. In the early 1900s, most U.S. industrial plants generated their own electricity and many used the exhaust steam for industrial processes; many utility companies supplied cogenerated steam to large in-



Source: E. P. Gyftopoulos (Massachusetts Institute of Technology, Cambridge, MA) and J. P. Davis (Thermo Electron Corporation, Waltham, MA), Presentation to the Governor's Commission on Cogeneration, 28 October 1977.

Figure 17-9. OIL SAVINGS FROM STEAM TURBINE COGENERATION

dustrial users and densely populated urban areas. By 1909, an estimated 150 utility companies were providing district heating. Cogeneration operations in the United States declined because of the availability of natural gas heating and of relatively low-cost reliable supplies of electrical power from large generation plants located in sites remote from densely populated areas. Other contributing factors include the inability to transport steam economically over long distances, failure of installed cogeneration systems to achieve their promised high efficiency, and high maintenance and operating costs compared with electric power and natural gas heating. Renewed U.S. interest in cogeneration has resulted from the increased attention being given to energy conservation and rising fuel costs.

Government-sponsored projects include establishment of a data base of available low-temperature sources of heat in industry and the technologies for recovering that waste heat; evaluation of nine advanced concepts for industrial cogeneration in terms of performance, economics, and fuel requirements; identification and assessment of the best emerging technologies for industrial cogeneration; case studies of plants in five industries being used to generate and optimize site specific cogeneration systems; and evaluation of the use of fuel cells in specific plants of four different industrial sectors. The economics of cogeneration have also been studied. One such study concluded that, with federal loan guarantees, investment tax credits, and other incentives as a method of government enhancement of cogeneration, 500,000 bbl/day of fuel could be saved. In another study comparing industrial and utility ownership of a cogeneration power plant, it was found that increasing industrial and utility cogeneration could save $2 billion to $5 billion in capital expenditures per year through 1983, and up to 725,000 bbl/day of oil.

In Europe, industrial cogeneration is five to six times more common than in the United States. In 1972, 16 percent of West Germany's total power production was cogeneration by industries; in Italy, 18 percent; in France, 16 percent; and in the Netherlands, 10 percent. In addition, utility cogeneration systems produce 25 percent of the total electrical power needs of Bulgaria, the German Democratic Republic, the Federal Republic of Germany, Poland, Romania, Austria, Denmark, Finland, Sweden, Yugoslavia, and the USSR. Cogeneration has been so successful in Europe, compared with the United States, because reliable low cost electricity was not as widely available until the 1950s, and utility stations are smaller and more decentralized. Furthermore, Europeans historically have used hot water instead of steam as their heating fluid. Use of hot water offers advantages in economies of power generation and flexibility in heat storage and distribution. Finally, European policies, laws, and regulations are generally more favorable to cogeneration operations.

There are two fundamental types of cogeneration systems—topping and bottoming—differentiated on the basis of whether electrical (or mechanical) energy or thermal energy is produced first. In a topping system, electricity or mechanical power is produced first, and the thermal exhaust from the turbine is used as industrial process heat, for space heating, or in other applications (see Figure 17-9). In a bottoming system, thermal energy for process use (such as steel-reheat furnaces, glass kilns, and aluminum-remelt furnaces) is produced first, then the waste heat is recovered as an energy source for generating electricity or more mechanical power. Choosing a system depends on the balance of thermal energy and electrical (mechanical) power needed, and the level of waste heat available. R&D, sponsored

in part by the U.S. Department of Energy (DOE), is focused primarily on demonstration projects and technology development. New and innovative topping and bottoming systems are not expected to be available commercially until after 1985.

Topping Systems[13]

Steam turbines (Rankine engines), gas turbines (Brayton engines), and Diesel engines are the three primary heat engines used in cogeneration topping systems. A steam turbine system consists of a boiler and a backpressure turbine. The boiler can be fired by oil, natural gas, coal, wood, or industrial by-products and wastes. The turbine drives an electric generator and provides exhaust steam, still under pressure, for heating purposes. The overall efficiency of steam turbine cogeneration systems generally ranges from 65 to 85 percent; such systems require 4,000 to 6,000 Btu of fuel for each kWh produced. The amount of electricity produced increases in proportion to the pressure of the steam entering the turbine. Although capital costs for steam turbine topping systems can be high, the investment costs attributed to electrical generation are about $300 to $500/kW.

A gas turbine system consists of a gas turbine and waste heat recovery unit. Natural gas or light petroleum products (distillate oils) are used as fuels, and the combustion gases produced are used in the turbine to provide the mechanical shaft power that drives an electrical generator. The electrical conversion efficiency of gas turbine topping cycle systems typically is lower than that of steam turbines, and such systems require 5,500 to 6,500 Btu of fuel for each kWh produced. The exhaust of the gas turbine (at about 535 °C) is recovered both indirectly (via a heat exchanger) and directly for process heating applications, or indirectly (via a boiler) for generating process steam. In the last configuration, high-pressure steam produced in a waste heat recovery boiler can be passed through a steam turbine to yield either mechanical or electrical power before being used in a process.

A diesel system, consisting of a Diesel engine and a waste heat recovery unit, uses natural gas or distillate oil. The combustion of fuel in the engine yields the mechanical power that drives an electrical generator. Of the three topping systems, this cycle is the least efficient in producing electricity, and requires 6,500 to 7,000 Btu of fuel for each kWh produced. However, its optimum electricity-to-steam ratio is about twice that of gas turbine topping and more than eight times that of steam turbine topping. This makes the diesel system more attractive for use where the heating loads are low compared to electrical loads. The engine exhaust provides process heat or low-pressure process steam. For process heating applications, the exhaust (at about 260 °C) is used directly, or indirectly. Process steam of about 100 psi is generated in boilers that recover heat from the engine exhaust. In addition to the engine exhaust, heat can be recovered from a water-cooled engine jacket; low-pressure process steam (generally at about 25 psi) is produced. Total installation costs range from about $3 million for a 5 MW plant to $11 million for a 25 MW plant. The investment costs for electricity generation range from about $300 to $700/kW or more (the higher rates reflect costs of smaller plants, or slow-speed engines, or both), and maintenance is higher than the other topping systems. Typically, minor repairs are required every 7,000 to 10,000 hours and major overhauls, every 20,000 to 30,000 hours.

Topping systems under development include the use of Stirling engines, fuel cells, magnetohydrodynamics systems, and thermionic devices, as well as advanced Diesel engines

and gas turbines. The goal is to develop multifuel capabilities for systems currently restricted to one or two fuels (particularly scarce fuels) and to develop new systems with multifuel flexibility. New and improved systems with higher efficiencies and wider applicability also are being developed.

Bottoming Systems[13]

All bottoming systems are based on the Rankine cycle for waste heat recovery. Two types of Rankine cycles are used—steam and organic. Steam bottoming systems recover heat rejected from thermal processes at high temperatures. Steam systems operate within a heat temperature range of 150 to 535°C, with thermal efficiencies of 14 to 36 percent, and generally have capacities of over 500 kW.

Bottoming systems that use organic working fluids to recover thermal energy are available in limited sizes, ranging from 2 to 4 MW. Because these operate at lower temperatures (90 to 170°C), such systems can recover lower temperature waste heat. These systems have efficiencies of 13 percent. Work on bottoming systems is focused on further development of organic-fluid Rankine cycles, which are more flexible than steam Rankine cycles. Because the organic fluids vaporize at temperatures below 100°C, and are more efficient than water at higher temperatures, it should be possible to develop high-performance organic Rankine cycles. In the future, organic bottoming systems are expected to employ new fluids that will reduce the need for superheating and desuperheating, thus increasing efficiency and providing chemical stability at high operating temperatures.

Depending on the flow rate and temperature of the waste heat to be recovered and the type of bottoming system, installation costs vary from $700 to over $1,000/kW. Maintenance requirements and the reliability of organic systems generally are unknown because proved commercial experience is limited. However, the technology of component parts (for example, expansion turbines, fluid pumps, and heat exchangers) is proved. In addition, since organic systems operate at low temperatures, their reliability should be high.

Combined-Cycle Systems

Combined-cycle systems are comprised of two or more different thermodynamic cycles connected together in a way to gain maximum efficiency from the primary heat source. In most cases, both cycles are used for the same purpose—usually to generate electricity. Such systems using coal or coal-derived fuels offer significant improvements over conventional systems for electric power generation in terms of increased efficiency, potentially lower cost, and reduced environmental impact. The major combined-cycle options currently under development include open-cycle gas turbines, closed-cycle turbines, fuel cells (see Chapter 15), and magnetohydrodynamics (see Chapter 16). Advances in combined-cycle power plants focus on high-temperature gas turbines combined with steam systems.

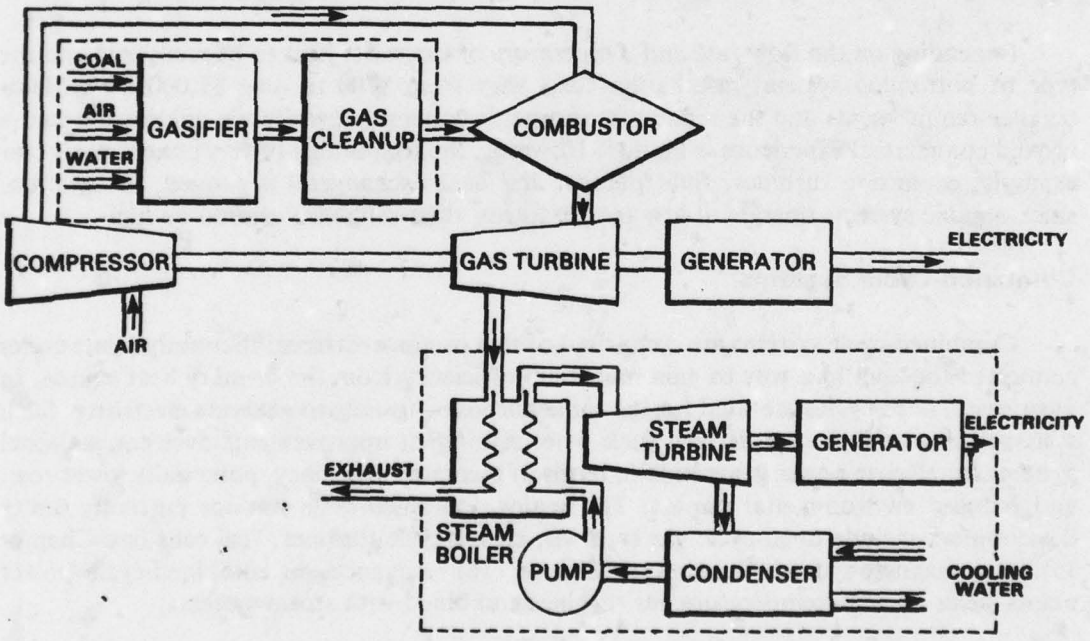
Open-Cycle Gas Turbine Combined Cycles[15]

Open-cycle gas turbines that burn natural gas and distillate oils are used commonly for utility peak load applications. Combined-cycle power plants couple such gas-turbines with

steam-turbine technology to reduce the cost of electricity. A number of oil-fired combined-cycle plants are currently in utility service. Relatively low capital investment/kW, higher conversion efficiency, capability for base and intermediate-load service, and future potential for using low-Btu gas from coal are factors making investment in new combined-cycle units increasingly attractive to electric utilities.

The concept of this advanced system (see Figure 17-10) is to burn coal or coal-derived gaseous or liquid fuels in air to produce a high-temperature gas (1,425 °C or higher) before expanding it through the turbine to produce electricity. After expansion, remaining hot gases can be used to generate steam in a conventional steam turbine plant to produce additional electricity. The open-cycle gas turbine/steam system forms a combined-cycle power plant with potentially greater efficiency than today's standard steam plant. Integrating a combined-cycle system with a low-Btu coal gasifier appears to be most promising from the standpoints of efficiency, cost of electricity, and emissions.

With this system, crushed coal, water, and compressed air are fed into the gasifier. Hot gases are passed through a cleanup system for removal of particulates and chemical contaminants, and are burned in a combustor prior to driving the gas turbine electric generator. From the turbine, the expanded gases are routed through a steam generator, relinquish their remaining heat, and are exhausted to the atmosphere. Steam thus generated is expanded through a steam turbine driving an electric power generator. Exhausted steam is condensed, and a pump arrangement feeds the fluid back through the steam generator.



Source: U.S. Department of Energy, "Fossil Energy Program Summary Document, FY 1980, Assistant Secretary for Energy Technology," January 1979.

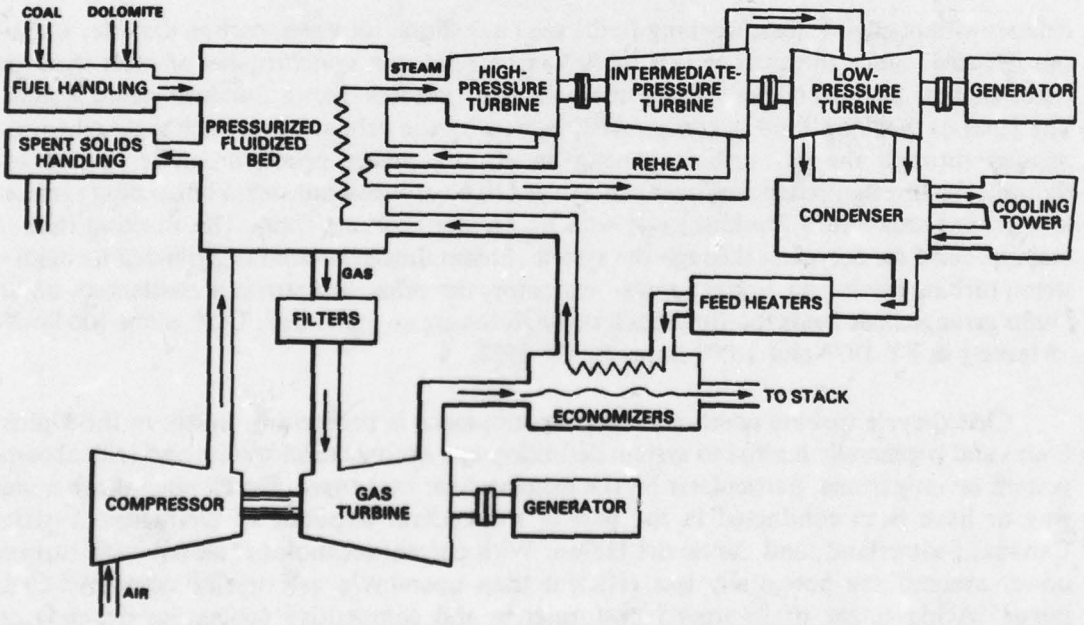
Figure 17-10. OPEN-CYCLE GAS TURBINE/STEAM TURBINE SYSTEM

Another variation of the combined gas turbine/steam turbine system features direct combustion of coal in a pressurized fluidized bed (see Figure 17-11). The fluidized bed can be operated at high excess air as a combustor for a gas turbine or at low excess air with heat extracted from the bed by steam or air tubes within the bed. In the latter case, the energy extracted from the bed feeds into the steam turbine or gas turbine cycle. Because these systems operate directly on coal, efficiency levels are expected to be about 40 percent, even though gas turbine inlet temperatures range from 870 to 980°C. At these temperatures, the products of coal combustion must be cleaned to the tolerance level of a gas turbine; therefore, the technical and economic feasibility of hot-gas cleanup systems that can meet gas turbine requirements must be determined.

Closed-Cycle Turbine Combined Cycles[16]

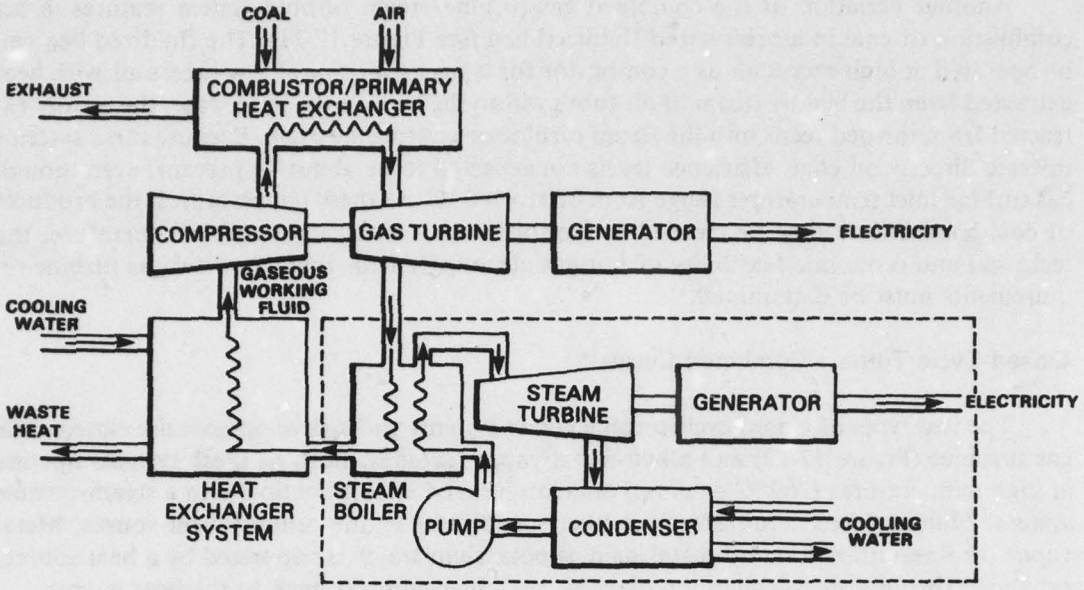
The two types of closed-cycle turbine power systems under development use closed-cycle gas turbines (Figure 17-12) and alkali-metal vapor turbines. Both of these systems operate at high temperatures (760°C or more) and can be used in conjunction with a steam-turbine system. Fluidized-bed combustors are likely candidates as the primary heat source. Metal vapor turbines utilize a liquid metal such as potassium which is vaporized by a heat source, expanded through the turbines, condensed, and then pumped back to the heat source.

As in the open-cycle gas turbine system, the closed-cycle system can burn coal or coal-derived fuels. Because the working fluid is contained within a sealed system and is recir-



Source: U.S. Department of Energy, "Assessment of Technology for Advanced Power Cycles," FE-1216-5 (Washington, D.C.: National Academy of Sciences, 1977)

Figure 17-11. PRESSURIZED FLUIDIZED-BED BOILER/GAS TURBINE SYSTEM



Source: U.S. Department of Energy, "Fossil Energy Program Summary Document, FY 1980, Assistant Secretary for Energy Technology," January 1979.

Figure 17-12. CLOSED-CYCLE GAS TURBINE/STEAM TURBINE SYSTEM

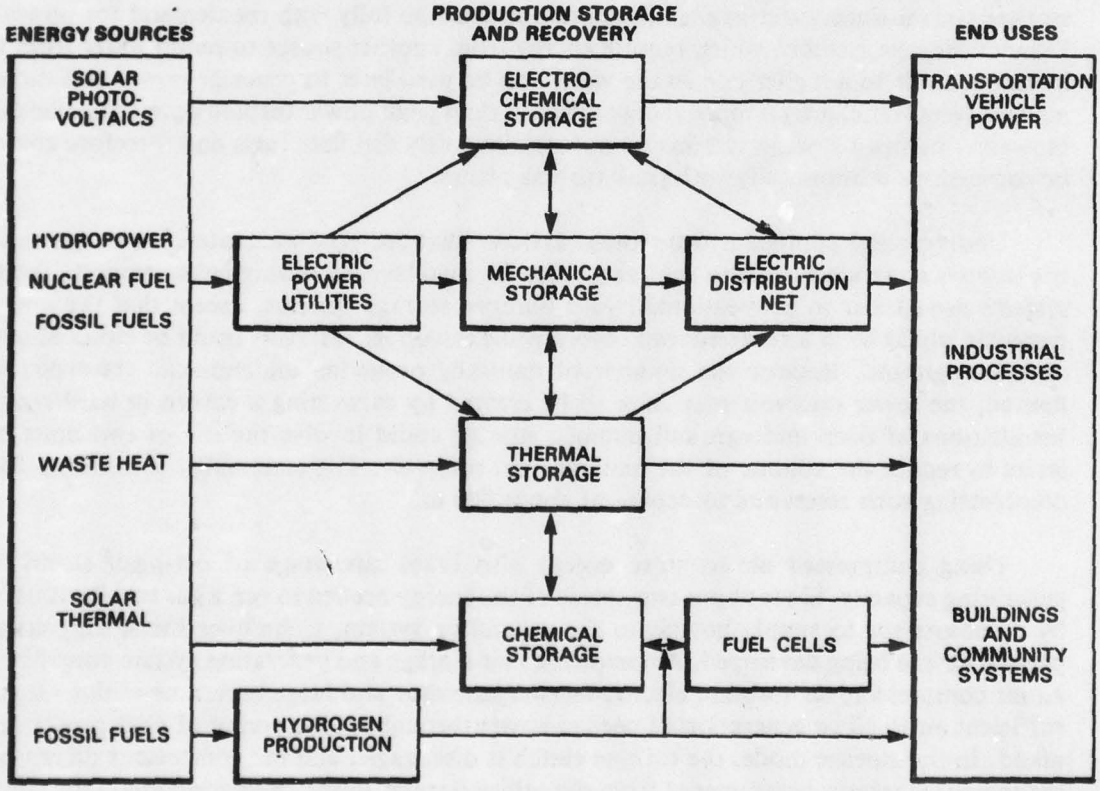
culated with negligible loss, working fluids such as helium, nitrogen, carbon dioxide, and air can be used. Since the turbine can be driven by relatively noncorrosive or inert working fluids such as helium, it can operate at higher temperatures than a standard steam system. The gaseous working fluid is compressed, heated by the primary heat exchanger, then expanded through the gas turbine driving an electric power generator. After expansion through the turbine, remaining heat can be used in a conventional steam bottoming cycle or in a lower temperature Rankine cycle with an organic working fluid. The working fluid is recompressed for recycling through the system. Steam thus generated is expanded through a steam turbine driving an electric power generator, the exhausted steam is condensed, and a pump arrangement feeds the fluid back through the steam generator. DOE plans 500 hours of testing in FY 1979 and 1,000 hours in FY 1980.

Closed-cycle turbine combined-cycle development is proceeding slowly in the United States and is generally limited to system definition and optimization studies and critical component investigations, particularly on the primary heat exchanger. Developments are under way or have been conducted in the past in the Federal Republic of Germany, Austria, Canada, Switzerland, and the Soviet Union. With current technology, closed-cycle turbine power systems are potentially less efficient than open-cycle gas turbine combined-cycle plants. Achievement of improved performance and competitive economics depends on resolving a number of high-temperature component and materials problems. Commercial-scale coal-fired power system applications are not expected in the United States through 1990.

ENERGY STORAGE

Potential applications of energy storage technologies are found in transportation, building heating and cooling, industrial processes, and the utilities. Pumped water storage is the only proved large scale technology. Hydropower, using gravity storage in a reservoir that refills continously from the natural flow of a river, clearly is the simplest and most desirable method of energy storage, since no energy need be consumed to achieve storage. All other storage processes waste significant amounts of energy, the source of which is usually a depletable fuel resource. Thus, the merits of storing energy by systems that waste a significant amount of energy in the process must be weighed against the alternative of building additional peaking generation plants.

As shown in Figure 17-13, there are basically four types of energy storage systems: mechanical, thermal, chemical, and electrochemical. One or more of these systems may be appropriate for storing energy from the various energy sources. Storage systems may be categorized further as external or internal. External storage systems take the electrical output of the plant and store that which is not needed to supply the demand at that time. In this system, the power plant would operate at the maximum possible output at all times. External



Source: U.S. Department of Energy, Assistant Secretary for Energy Technology, "Program Overview FY 1978, Energy Storage Systems Division of the Department of Energy," December 1977.

Figure 17-13. ENERGY SOURCES, STORAGE SYSTEMS, AND END USES

systems include mechanical storage systems (hydro pumped storage, compressed air, flywheels, superconducting magnets) and chemical and electrochemical storage systems (hydrogen, lead-acid batteries, advanced batteries). Internal storage systems take thermal energy directly from the receiver and store it before electricity is generated, and include both sensible and latent heat thermal storage systems.

A recent assessment of energy storage technology indicates that, in addition to pumped hydro and compressed air, thermal storage systems and advanced batteries will be available by 1985. Flywheels and hydrogen storage systems may become available by 2000, and superconducting magnetic energy storage systems after 2000.

Mechanical Storage Systems[17-20]

Mechanical storage systems use gravity water storage, pumped water storage, underground pumped hydro storage, compressed air systems, flywheels, or superconducting magnets. Gravity water storage and conventional pumped water storage systems, described in Chapter 8, are commercially available and in wide use throughout the world. Gravity water storage, which is used to collect and hold water at high elevations so the energy available from it can be converted to electrical energy as required, is a valuable energy storage system since water availability does not coincide fully with the demand for power. Pumped storage systems, which require energy from another source to pump water from a lower reservoir to a higher one so the water can be used later to generate power at a more advantageous time, are no more energy efficient than peak power turbine generating plants. However, pumped storage systems do not require costly distillate fuels and therefore could be competitive economically with peak turbine plants.

Underground pumped hydro storage systems have received wide attention by the electric utilities as an alternative to the gas turbine for load leveling during peak demand. These systems are similar to conventional hydro pumped storage systems, except that the lower reservoir would be in a subterranean cavern while the upper reservoir could be either above or below ground. Because the number of naturally occurring underground reservoirs is limited, the lower reservoir may have to be created by excavating a cavern in hard rock. Installations of deep underground pumped storage could involve the use of two units in series to reduce the volume of the underground reservoir. The technology is available for constructing such reservoirs to depths of about 900 m.

Using compressed air to store energy also takes advantage of off-peak electrical generating capacity. Since about two-thirds of the energy needed to run a gas turbine is used by a compressor to supply hot air to the generating system, techniques for storing compressed air are being developed. A compressed air storage and generation system consists of an air compressor, air turbine, electric motor/generator and large cavern or tank to store sufficient air to allow generation of needed power throughout the period of peak power demand. In the storage mode, the turbine clutch is disengaged and the compressor driven by the motor/generator using energy from the utility system. In the generation mode the compressor clutch is disengaged and the motor/generator is driven by the turbine using compressed air from storage. Storage could be in a natural underground cavern, porous underground reservoir, depleted gas and oil fields, or man-made cavern such as a depleted

salt mine. The world's first compressed air storage plant has been completed in Huntoff, West Germany, but it is conservative in design and not well suited to U.S. conditions because there is no reclamation of exhaust heat and the compressors are small compared to the turbine, resulting in a 4:1 ratio between the charging time and the discharging time.

Compressed air storage is superior to gas turbine peak power generating systems in terms of energy efficiency and appears to be competitive economically with peak power systems because of the more effective utilization of the installed turbines. To increase the efficiency of compressed air storage systems, heat generated when the air is compressed could be stored and used to preheat the incoming air. The main disadvantage of a compressed air storage system is the gradual reduction of power output because of falling air pressure as air is used from storage. To overcome this difficulty, air can be stored in a variable volume tank or in a hydraulically compensated underground storage facility. The storage reservoir must be large since about 1,500,000 cubic feet of air at 600 psi is required for 5 hours of operation at 20,000 kW of power output. With either type of system the losses amount to about 50 percent of the output energy. Alternatives to the conventional compressed air concepts are being investigated, including the storage of the heat of compression (adiabatic compressed air storage) and alternative air heating schemes in the expansion step—perhaps with combustion of oil. Possible air heating options include use of coal in fluidized-bed units and use of hybrid systems with coal gasifiers.

The flywheel, a massive wheel that stores rotational kinetic energy, has been used to smooth out the power available from one- or two-cycle engines and adjust for uneven loads. Flywheels offer 80 to 90 percent efficiency, but more research and development (new materials, new shapes) is needed to make them practical and economical for large-scale storage. The new uses of this device take advantage of the reversibility of the electric motor/generator. With proper design, an electric engine can be run as a motor with an input of electric power or as a generator with an input of mechanical power. Flywheel storage is being tested both for transportation and for use in electric utility systems. In buses, an electric motor energizes the flywheel and the bus runs on this energy for a few miles between recharging stations. The most important use will probably be regenerative braking. A subway train, for instance, may use a flywheel to slow down (by transferring energy to it from the wheels), then reuse this energy for acceleration. In such stop-and-start operations, energy savings as high as 30 percent may be realized (and the subway tunnels will be more comfortable without the heat dissipated by friction braking). In utilities, a large flywheel located near a point of electric power demand could be set spinning by a motor using off-peak power and then drive the motor as a generator when additional electricity is needed. The possibility of using flywheel storage in generating electric power has been enhanced by several advanced flywheel designs using modern high-strength materials, but these advanced flywheel concepts presently do not appear to economically competitive.

A far-term storage system concept that could become competitive is the concept of direct electrical storage in superconducting magnets. Such a system would consist of a large magnet in a solenoidal or toroidal configuration, which would be cooled to temperatures (near absolute zero), where it would lose virtually all electrical resistance to direct currents (this characteristic is called superconductivity). At such temperatures, once started, a direct current will persist indefinitely and maintain the magnetic field for possible future energy

withdrawal. The efficiency with which stored energy can be recovered in such a system is very high, 85 to 90 percent, which is one of the main advantages of the concept for large-scale electricity storage. There are many small superconducting magnets in existence, but present materials and techniques could not produce a competitive system for utility use. Various design studies show that the capital cost would be minimized if the superconducting magnet were placed underground using the surrounding rock as structural support. Because the cost of installation and the cooling losses increase relatively slowly with the size of the magnetic storage system, it has been found that such systems would be most competitive when supplying rather high power ratings. Studies have shown that magnetic storage system operating costs approach those of conventional hydro pumped storage only for systems that could supply the entire demand of a typical utility rather than just the peak load.

Thermal Energy Storage Systems[17-22]

Thermal energy storage systems may provide high-temperature or low-temperature storage. Low-temperature methods are used in conjunction with district heating or to provide comfort heating and/or cooling by using off-peak power. High-temperature systems store thermal energy for load leveling or peak shaving for use with a heat engine to generate electricity.

Most thermal storage concepts can be classified as either sensible heat storage or latent heat storage. Sensible heat content of a system is characterized by the system's temperature, and the energy capacity of the material depends on the temperature change that can be tolerated. Latent heat (phase change) content is characterized by the changing phase of a medium (solid, liquid, or gas) and generally occurs isothermally or over a small temperature increment. Thermal energy also can be stored by means of reversible chemical reactions.

Sensible Heat Storage Systems

Sensible heat storage systems involve the addition of thermal energy to the storage material during charging, with a resultant increase in the temperature of the storage material. Materials to be used in sensible heat storage systems should have a high specific heat and a high density, and be relatively stable over a wide range of temperatures. Also, any storage material must be inexpensive, readily available in large quantities, nonhazardous, stable over long periods of time, and environmentally acceptable.

The primary candidate for sensible heat storage material is water, which conforms to all of the above criteria and has the added bonus of being a material for which there exists a vast body of data and engineering experience. The major difficulty with water is its relatively high vapor pressure at the storage temperatures of interest, which would lead to rather expensive storage vessels. Other possible materials for sensible heat storage include liquid metals, molten salts, organics such as various oils, and rocks. Although all these materials do not have the heat capacity of water, they do have low vapor pressures, which would offer possible savings in storage vessel cost.

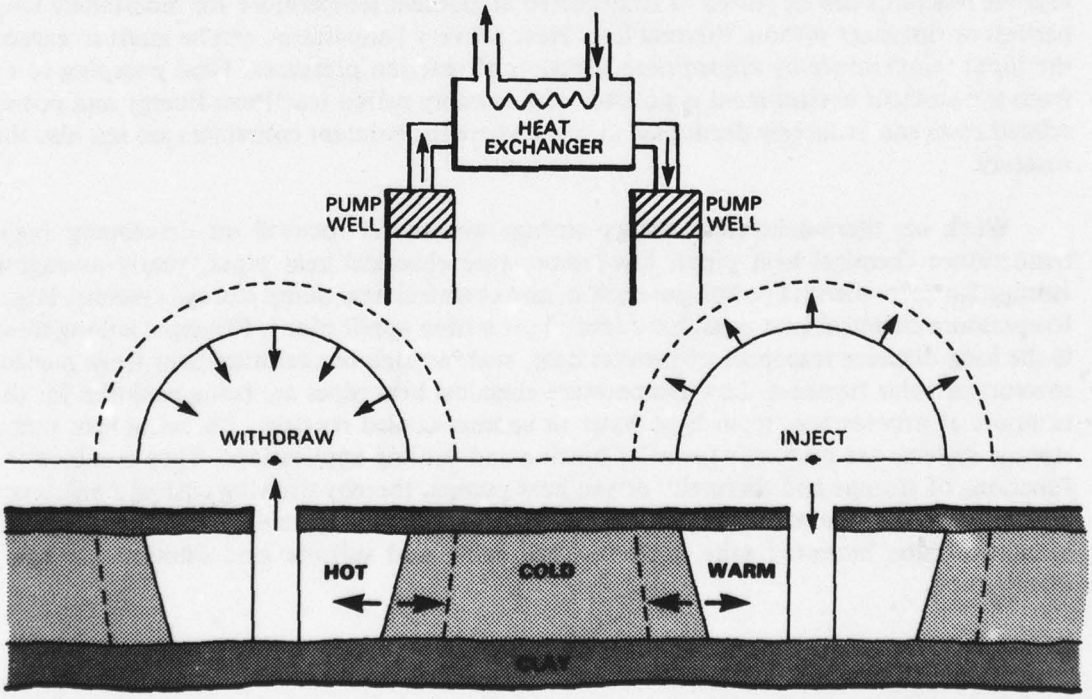
Aquifer storage of heated water appears to be particularly well suited for seasonal storage of large amounts of thermal energy. The volume of storage available in aquifers is

significant and storage costs should be quite low if the hot water storage is spread over enough units, that is, if large, efficient wells are used. Heat loss per unit of heat stored in an aquifer (for a given unit of time) decreases as the amount of energy stored increases. Losses occur principally at the interface between hot and cold water in the aquifer and between hot water and the layers of low-permeability clay or rock, which confine the vertical movement of water in an aquifer.

Aquifer storage of thermal energy is feasible technically although it remains to be demonstrated on a large scale. A heat storage well concept is shown in Figure 17-14. Two wells are drilled into a confined aquifer. Groundwater pumped from one well is injected into the same aquifer through another, nearby well. Initially, the aquifer matrix and the native groundwater are cold. To begin storing heat, cold groundwater is pumped through a heat exchanger, heated, and injected into the "hot" well. When stored heat is to be recovered and used, water is pumped from the hot well, circulated through the heat exchanger where it gives up its useful heat, then is injected into the "warm" well—no longer cold, because the lowest useful temperature in the heat system is higher than the native groundwater temperature.

Latent Heat Storage Systems

Latent heat storage permits charging and discharging of a storage device without large temperature changes. The most suitable phase change is the liquid/solid transition (heat of



Source: Charles F. Meyer, "Large-Scale Thermal Energy Storage for Cogeneration and Solar Systems," *Energy Technology V, Challenges to Technology* (Washington, D.C.: Government Institutes, Inc., 1978).

Figure 17-14. HEAT STORAGE WELL CONCEPT

fusion). The liquid/gas transition (heat of vaporization), though connected with large internal energy changes, involves major volume changes that cause difficult mechanical design problems. The desirable properties of materials for latent heat storage systems include a high latent heat of fusion, high specific heat, high density, and a melting temperature compatible with power plant designs—between 260 and 590°C. Fused salt eutectic mixtures melting at 450 to 700°C can store 200,000 to 600,000 Btu/ton, which means that a 10 MW solar power plant would require about 3,000 metric tons of eutectic storage for a 1 day reserve.

The use of latent heat thermal storage systems is very attractive because of the theoretically high energy storage density, typically two to five times greater than systems using water (steam). However, phase-change materials normally possess relatively low thermal conductivities and, due to the decrease in volume during solidification, the formation of significant interface thermal resistance is probable. Both of these problems limit the rate at which the storage system can be charged and discharged. Heat exchanger design will be difficult due to the significant forces resulting from the density changes occurring during the phase change. While these problems do not appear to be insurmountable, they do lead to higher costs of latent heat thermal storage systems.

Thermochemical Heat Storage Systems

Storing or transporting thermal energy by means of reversible chemical reactions provides potentially higher energy densities than those achievable with sensible or latent heat, and the reactants can be stored or transported at ambient temperature for indefinitely long periods or distances without thermal loss. Heat delivery temperature can be made to exceed the input temperature by appropriate selection of reaction pressures. Heat pumping to or from the ambient environment is possible with suitably paired reactions. Energy and power related costs can be largely decoupled in cases where the reactant containers are not also the reactors.

Work on thermochemical energy storage systems is focused on developing high-temperature chemical heat pipes, low-temperature chemical heat pipes, yearly averaging storage for solar thermal power generation, and chemical heat pump storage systems. High-temperature chemical heat pipes have several promising applications. Principal among these is the long distance transport of process heat, such as high-temperature heat from nuclear reactors or solar furnaces. Low-temperature chemical heat pipes are being explored for the tranport of process heat from light water or sodium-cooled reactors. Chemical heat pump storage systems are primarily for solar heating and cooling applications. They combine the functions of storage and thermally driven heat pumps, thereby deriving cost and efficiency advantages over separate solar heating, cooling, and storage systems. Concepts using ammoniated salts, hydrated salts, methanolated salts, and sulfuric acid dilution are being investigated.

Chemical and Electrochemical Storage Systems[19,21,23]

Chemical and electrochemical storage is very stable and provides the high energy density needed for transportation. Much of the new research and development effort, therefore, focuses on such systems.

Hydrogen storage systems, described in Chapter 14, are basically chemical storage systems. Conversion of hydrogen to electric energy can be done in fuel cells, combustion devices, boilers, or gas turbines. Hydrogen storage systems can offer an attractive alternative to conventional gas turbines and advanced combined-cycle systems.

Another chemical energy storage device is the fuel cell (see Chapter 15), which converts chemical energy directly into electricity. Fuel cells are very much like batteries, but with the important difference that the components that react to produce the electric current are continuously fed in and the reaction products are removed. A fuel cell, therefore, is a continuous source of electric power and does not need recharging like a battery. Fuel cells are able to produce electricity from natural gas on demand and may become an important part of a future hydrogen-based energy system.

Batteries are well known and successful storage devices and seem to offer the only method of storing energy in dispersed locations while retaining the possibility of reconverting the stored energy to electricity with high efficiency. A number of different electrochemical systems have been developed, or offer prospects for development, into practical storage batteries for utility applications. Batteries are used widely to store direct current electrical energy in the form of chemical energy. According to the extent of reversibility of the chemical reactions, batteries are divided into two classes: primary and secondary. For all practical purposes, the chemical reactions in a primary battery are irreversible because the generation of electric current consumes materials inside the battery which cannot be replenished by recharging. In secondary batteries, the chemical reactions are reversible, therefore the secondary battery can be restored to its original chemical state by a recharging process.

Batteries consist of two dissimilar electrodes, an electrolyte, and electrode separators in a suitable container. One electrode is in a reduced state and the other is in an oxidized state. When the battery is discharging, the reduced electrode is oxidized (electron source) and the other electrode is reduced (electron sink).

The types of storage batteries most commonly used are lead-acid, nickel-iron, nickel-cadmium, and zinc-silver. Each of these batteries has favorable characteristics for particular applications. Nickel-iron batteries are used where ruggedness is important. Zinc-silver batteries are ideal when high discharge rates are required. Nickel-cadmium batteries are desirable when minimum gas generation is essential. Lead-acid batteries are low in cost and sustain moderate discharge rates and, thus, are the most widely used.

When the terminals of a battery are connected to an external load circuit, electrons flow from the negative plate to the positive plate through the load circuit. In the lead-acid battery, sulfate ions combine with lead to form lead sulfate at the negative plate and the hydrogen ions and sulfate ions react with lead peroxide to form water and lead sulfate at the positive plate. To reverse the chemical reactions taking place during discharge, the current must be passed through the cell in the opposite direction to that of discharge. Therefore, to recharge a battery, a reversed charging voltage greater than the battery voltage is applied to the terminals.

Among the most interesting new ideas are the molten salt batteries whose electrodes are molten sodium, Na, and sulfur, S, separated by a solid electrolyte (a ceramic material that allows the sodium atoms to pass). These NaS batteries have energy densities greater than 220 Wh/pound (and comparable power densities). Another significant advantage is their ability to undergo many charge-discharge cycles. Duty cycles of 2,000 to 3,000 may be possible (and necessary). Since the electrodes are liquid, there is no geometric (or other) structure that needs to be reproduced. The chief disadvantage of NaS batteries is that they must be maintained at 250 to 330°C, an added complication for vehicle batteries. Present plans call for the batteries to be very well insulated, and these batteries will likely be able to store, for several days, the heat energy given off when they are charged.

The use of batteries for load leveling has the specific advantage of distributed storage, with its economic and siting benefits. Rapid installation and demand responsive capacity growth also are advantages of the basically modular storage units. For the near term, the only commercially available battery is the lead-acid type for which there exists a large body of data and against which any advanced battery system will be compared. However, no lead-acid batteries combine all of the characteristics required in a utility storage system.

Possible advanced battery systems include zinc-chlorine, sodium-sulfur, lithium-metal-sulfide, and sodium-chloride. Such systems, which can be used to store off-peak power and electricity generated by solar, wind, and other alternative energy sources, appear to be competitive with present peaking units as well as with other storage systems.

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APPENDIX A
GOVERNMENT ACTIVITIES

APPENDIX A—GOVERNMENT ACTIVITIES

DEPARTMENT OF ENERGY[1-3]

The Department of Energy (DOE) was activated by President Carter on 1 October 1977, in accordance with the Department of Energy Organization Act (P.L. 95-91). Creation of DOE gave direction and focus to the nation's energy future by providing the framework for carrying out a coherent and comprehensive national energy plan. As one of its objectives, DOE will help bring the public and private sectors together in an effort to balance energy supply and demand.

Energy-related functions and personnel were transferred to DOE from the Federal Energy Administration; Federal Power Commission; Energy Research and Development Administration; Interstate Commerce Commission; and the Departments of the Interior (DOI), Defense (Navy), Commerce, and Housing and Urban Development. DOE coordinates its energy programs with those remaining with other agencies, including energy leasing policy with DOI, rural electrification loans with the Department of Agriculture, fuel efficiency standards with the Department of Transportation, and international energy activities with the Department of State.

DOE's organizational structure, shown in Figure A-1, facilitates the evolution of energy technologies through the research, development, and commercialization phases. In addition, DOE maintains an extensive field organization (also shown in Figure A-1), consisting of regional offices; power marketing, transmission, and production facilities; energy technology centers and laboratories; and defense-related laboratories and weapons facilities.

DOE's missions include:

- *Energy supply—research and technology development,* oriented toward developing new and improved energy technologies. Basic research, technology development, engineering development, and demonstrations are included in this mission.
- *Energy supply—production, demonstration, and distribution,* oriented toward developing plans and projects and determining requirements for expanded domestic production of coal, oil, natural gas, electricity, solar, geothermal, nuclear, and other energy resources. Activities also performed within this mission include ensuring appropriate development and utilization of energy resources and support facilities, demonstrating new technologies to encourage their use by the private sector, administering federal energy supply reserves, performing uranium enrichment services, and producing and distributing other energy fuel forms.
- *Conservation,* oriented toward reducing end-use energy consumption and increasing energy efficiency in all sectors of the national economy.
- *Regulation,* including the development of regulatory programs for compliance and

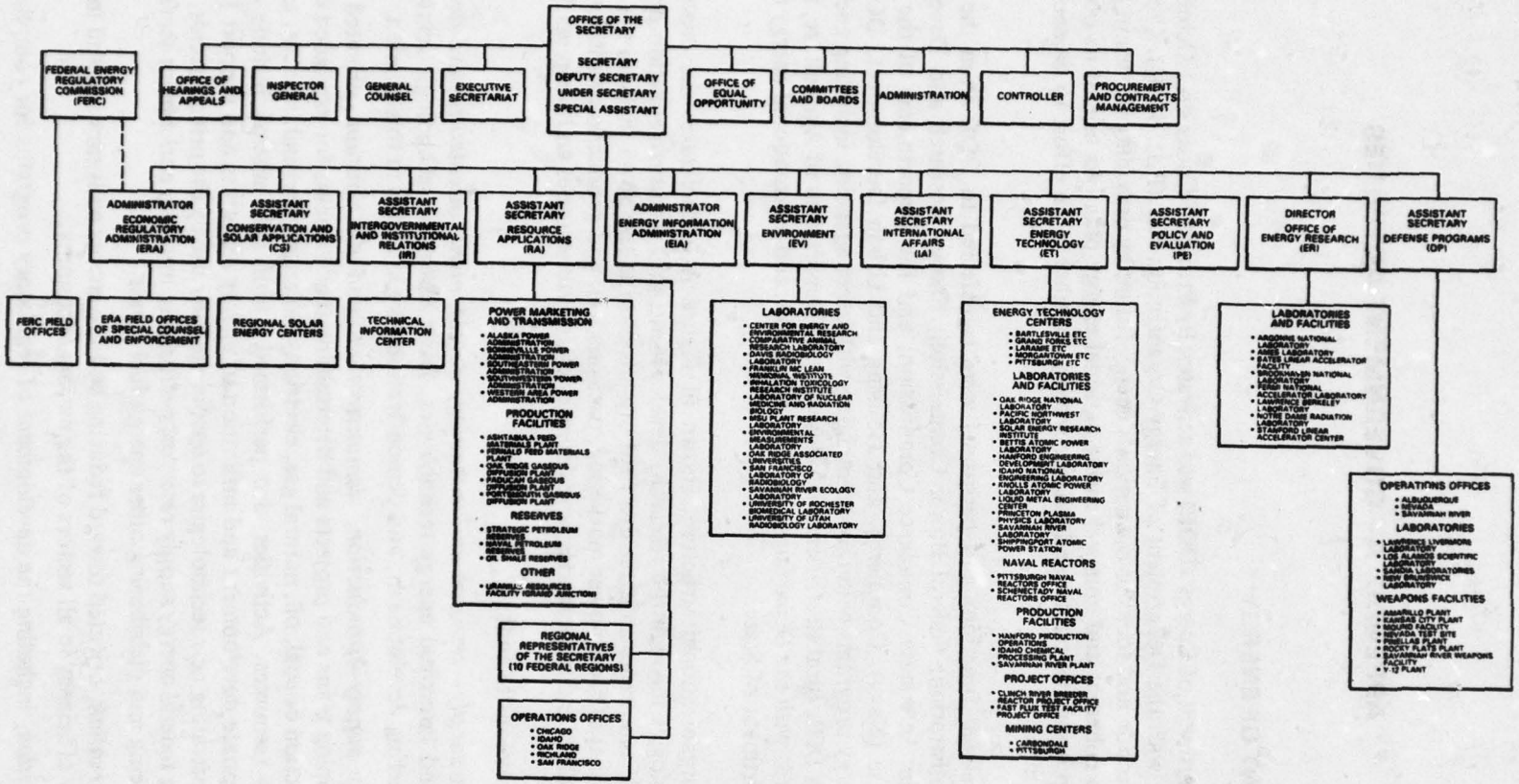


Figure A-1. DEPARTMENT OF ENERGY ORGANIZATION

allocation along with legal and appeals activities. DOE's regulatory elements are the Federal Energy Regulatory Commission and the Economic Regulatory Administration.

- *Emergency preparedness,* ensuring that emergency petroleum conservation measures are created to provide energy demand restraints to comply with the shortfall resulting from any future energy crisis, as well as to meet U.S. energy requirements under the International Energy Agreement. This mission provides that a system for rationing gasoline and diesel fuel be available, along with appropriate contingency measures in case of nonpetroleum energy supply problems. Standby allocation regulations and refinery yield programs also must be available. As part of this program, DOE operates an Emergency Management Information System, designed to provide real-time information on energy supply availability on a national scale.
- *Energy information,* oriented toward developing, collecting, and disseminating a broad range of energy-related information, including effects of both national and international energy policies, actions, and developments on the national economy and standard of living; industrial performance in the area of energy resources production and distribution; and the historical, current, and projected energy situation and effect of energy policies and matters on energy supply, demand, price, and other factors.
- *Environment,* including identifying and evaluating environmental impacts associated with national energy policy and with energy supply and conservation activities and establishing environmental policies related to DOE programs.
- *Policy and management,* including developing and analyzing alternative energy policies, legislation, and DOE programs; developing a national plan for research, development, and demonstration of energy-related technology; and conducting a decontamination and decommissioning program for disposition of surplus radioactivity-contaminated facilities and sites.

ENERGY LEGISLATION

Table A-1 shows the major congressional committees with jurisdiction over energy and related environmental programs and legislation. Since the Arab oil embargo, the Congress has been instrumental in formulating national energy policy and developing the governmental apparatus to respond to the energy crisis. Major legislative accomplishments have included the Emergency Petroleum Allocation Act, Federal Energy Administration Act, Energy Supply and Environmental Coordination Act, Energy Policy and Conservation Act, and Energy Conservation and Production Act.

The Ninety-fifth Congress was the first to consider a comprehensive national energy plan. The resulting National Energy Act has five components:

- P.L. 95-617—Public Utility Regulatory Policies Act of 1978.
- P.L. 95-618—National Energy Tax Act.
- P.L. 95-619—National Energy Conservation Policy Act.
- P.L. 95-620—Powerplant and Industrial Fuel Use Act.
- P.L. 95-621—Natural Gas Policy Act.

Table A-1. CONGRESSIONAL COMMITTEES WITH JURISDICTION OVER ENERGY AND RELATED ENVIRONMENTAL PROGRAMS

Committee	Jurisdiction
Senate	
Energy and Natural Resources Committee	Energy policy; RD&D; production, distribution, and utilization; nonmilitary development of nuclear energy.
Environment and Public Works Committee	Environmental policy and R&D, resource utilization and conservation, nonmilitary regulation and control of nuclear energy.
House	
Armed Services Committee	Conservation, development, and use of naval petroleum and oil shale reserves; military applications of nuclear energy.
Interior and Insular Affairs Committee	Domestic nuclear energy industry and R&D, geological survey, mineral sources on public lands (and mining interests generally), petroleum conservation on public lands, geothermal resources for producing water and power, selected matters related to environmental impacts of laws.
Interstate and Foreign Commerce Committee	Interstate oil compacts and petroleum and natural gas (except on public lands); regulation of interstate power transmission; regulation of nuclear and nonnuclear energy facilities and use; the Clean Air Act; oversight functions with respect to laws, programs, and government activities affecting nuclear energy; environmental protection in general.
Committee on Science and Technology	Energy (except nuclear) and environmental R&D.

These and other important energy-related laws are described briefly in Table A-2. The National Energy Act is expected to result in reduced oil imports, increased use of fuels other than oil and gas, and more efficient and equitable use of energy in the United States.

INTERNATIONAL ACTIVITIES[4,5]

The United States recognizes its role as a major energy producing and importing nation and, as such, actively participates in international organizations and agreements for exchange of energy technology R&D and cooperative conservation of limited energy sources. The Assistant Secretary for International Affairs (IA) of DOE has principal responsibility for coordinating U.S. involvement in international energy programs within the context of domestic energy strategies and foreign policy objectives. IA cooperates with the Department of State and other federal agencies concerned with international programs, as appropriate, and manages U.S. liaison with the International Energy Agency (IEA), a major focus of U.S. international energy activity.

International Organizations

Through IEA, the United States participates with Austria, Belgium, Canada, Denmark, the Federal Republic of Germany, Greece, Ireland, Italy, Japan, Luxembourg, the Netherlands, New Zealand, Norway, Spain, Sweden, Switzerland, Turkey, and the United Kingdom to promote secure oil supplies; develop an emergency self-sufficiency in oil sup-

Table A-2. SUMMARY OF SIGNIFICANT ENERGY-RELATED LEGISLATION

Law Number	Date Enacted	Public Law
93-159	27 November 1973	**Emergency Petroleum Allocation Act (EPAA)** authorizes the President to establish mandatory allocation and pricing regulations for crude oil and other petroleum products. Authorities granted by EPAA were extended and amended by the Energy Policy and Conservation Act of 1975.
93-275	7 May 1974	**Federal Energy Administration Act** established the Federal Energy Administration (FEA) to plan and conduct programs related to production, conservation, use, control, distribution, rationing, and allocation of all forms of energy. The FEA was the first federal agency established specifically to address the nation's energy problems.
93-319	22 June 1974	**Energy Supply and Environmental Coordination Act** provides the United States with the means to meet its fuel needs in a manner consistent with its commitment to protect the environment. Under the Act, the FEA administrator (now the Secretary of DOE) may prohibit (by order) any power plant or major fuel-burning installation from burning natural gas or petroleum products as its primary energy source, if it has the capability and equipment to burn coal. Orders also may be issued during design and construction phases to require that the facility be capable of using coal as its primary energy source.
93-409	3 September 1974	**Solar Heating and Cooling Demonstration Act** establishes a program to demonstrate and evaluate solar heating and combined solar heating and cooling technologies for eventual commercial application.
93-410	3 September 1974	**Geothermal Energy Research, Development, and Demonstration Act** encourages commercial development of geothermal energy by providing for a project to implement R&D technologies related to exploration, extraction, and utilization of geothermal resources. An evaluation of the geothermal energy resource base is included in the project.
93-438	11 October 1974	**Energy Reorganization Act** established the Energy Research and Development Administration (later incorporated into DOE) and the Nuclear Regulatory Commission.
93-473	26 October 1974	**Solar Energy Research, Development, and Demonstration Act** provides for pursuit of a vigorous research program devoted to using solar energy on a commercial scale.
93-577	31 December 1974	**Federal Non-Nuclear Energy Research and Development Act** provides congressional policy guidance for establishing and conducting a comprehensive national R&D program to demonstrate practical application of all potentially beneficial energy sources and energy conservation technologies and to facilitate commercial availability of energy sources and technologies. This program as well as those established by P.L. 93-409, P.L. 93-410, and P.L. 93-473 are under the purview of ERDA (now DOE).
94-163	22 December 1975	**Energy Policy and Conservation Act** provides for increasing domestic energy supplies and availability, restraining energy demands, and preparing for energy emergencies. New emphasis is placed on the use of coal as a primary fuel source to alleviate the demand for oil and gas. An amendment to the act permits prohibition of any power plant or major fuel-burning installation from burning natural gas or petroleum products as its primary energy source. Other programs include establishment of automobile fuel economy standards, energy labeling for consumer products, State Energy Conservation Plans to help reduce energy demands on the state level, and the Strategic Petroleum Reserve system to supply petroleum in the event of a national emergency. The President is given broad flexibility to set prices for various categories of oil production, including the authority to recommend to Congress that various products be decontrolled.
94-370	26 July 1976	**Coastal Zone Management Act Amendments of 1976** require that outer continental shelf exploration, development, and production plans be consistent with approved state program plans and compensate local governments for the social, economic, and environmental impacts of coastal energy activity.
94-377	4 August 1976	**Federal Coal Leasing Amendments Act of 1975** allows for more leases; requires competitive bidding; and provides for additional revenue to the states for planning, building, and maintaining public facilities and services required when coal production increases. The act was passed because of increased emphasis on coal production on federal lands.

Table A-2. SUMMARY OF SIGNIFICANT ENERGY-RELATED LEGISLATION (CONT'D)

Law Number	Date Enacted	Public Law
94-385	14 August 1976	**Energy Conservation and Production Act** provides price increases for petroleum products obtained from tertiary enhanced recovery techniques and stripper wells; supplemental state energy conservation plans; use of performance standards and energy conservation features in new commercial and residential buildings receiving federal financial assistance; and financial and technical assistance in weatherizing dwellings of low-income persons.
94-580	22 October 1976	**Resource Conservation and Recovery Act** expands the federal role in solid-waste and resource-recovery technology in response to the shifting emphasis from disposal of materials and energy from solid wastes to their recovery.
95-87	4 August 1977	**Surface Mining Control and Reclamation Act** establishes a program to regulate coal surface mining operations to prevent environmental degradation.
95-91	4 August 1977	**Department of Energy Organization Act** created the Department of Energy (DOE) to provide a mechanism for effective management of a coordinated national energy policy. DOE, which encompasses the functions of previously established energy organizations, is to implement a comprehensive energy conservation program and a balanced energy R&D program.
95-95	7 August 1977	**Clean Air Act Amendments of 1977** affect coal conversion programs and the location of major fuel-burning installations and power plants. P.L. 95-95 prohibits significant deterioration of clean air areas. To stay within established air quality standards, plants and installations required to use coal as a primary energy source may have to limit their size, location, and production.
95-242	10 March 1978	**Nuclear Non-Proliferation Act** provides for more efficient and effective control over the proliferation of nuclear explosive capability; establishes initiatives to meet U.S. commitment to supply nuclear reactors and fuel to nations which adhere to non-proliferation policies; provides incentives to other nations to ratify the Treaty on the Non-Proliferation of Nuclear Weapons; and ensures controls by the United States over its exports of nuclear materials and technology.
95-590	4 November 1978	**Solar Photovoltaic Energy Research, Development, and Demonstration Act** establishes a 10-year, $1.5 billion program for the federal demonstration and commercialization of photovoltaics through a combination of research and subsidies to photovoltaics purchasers.
95-617	9 November 1978	**Public Utility Regulatory Policies Act of 1978** requires state regulatory authorities to consider alternative rate design standards, including time-of-day rates, seasonal rates, and prohibition of declining block rates; mandates new federal rules favoring cogeneration; and initiates loan programs to aid development of small hydroelectric projects.
95-618	9 November 1978	**National Energy Tax Act** provides tax credits to homeowners for installing conservation and solar energy equipment; imposes a graduated tax beginning in 1980 on fuel-inefficient automobiles; provides an investment tax credit to businesses for boilers using fuels other than oil and gas, and for other equipment using alternative fuels; and offers tax incentives for drilling for methane gas and geothermal energy.
95-619	9 November 1978	**National Energy Conservation Policy Act** provides a variety of incentives to conserve energy, including home weatherization grants for low-income families; conservation grants to schools, hospitals, local government buildings, and moderate-income residents; and solar loans to all homeowners. The bill also uses the federal government's buildings to test and commercialize solar heating, cooling, and electricity.
95-620	9 November 1978	**Power Plant and Industrial Fuel Use Act** establishes a regulatory framework aimed at forcing new and existing power plants and industrial facilities to use coal or other nonpetroleum fuels. It provides for exemptions where coal-conversion would be uneconomical or technically impractical, or would violate environmental requirements.
95-621	9 November 1978	**Natural Gas Policy Act** increases domestic production of natural gas by lifting the price ceilings on newly discovered gas (starting in 1985) but extending federal price controls in the interim to intrastate gas. The legislation also establishes new definitions of gas within a general regulatory framework, and provides an incremental pricing mechanism for industrial users.

plies; promote cooperative relations with oil-producing countries and with other oil-consuming countries; and reduce member-country dependence on imported oil by undertaking long-term cooperative efforts on energy conservation, accelerated development of alternative sources of energy, energy R&D, and uranium supply and enrichment.

U.S. involvement in IEA is focused primarily on participation in IEA's Committee on Energy Research and Development, which has working parties to conduct cooperative energy R&D projects (see Figure A-2). Currently, there are 14 working parties with projects in various energy technologies. The United States participates in all of these working parties, and serves as the lead country for those efforts directed at conservation, nuclear safety, ocean thermal energy conversion, and energy R&D strategy.

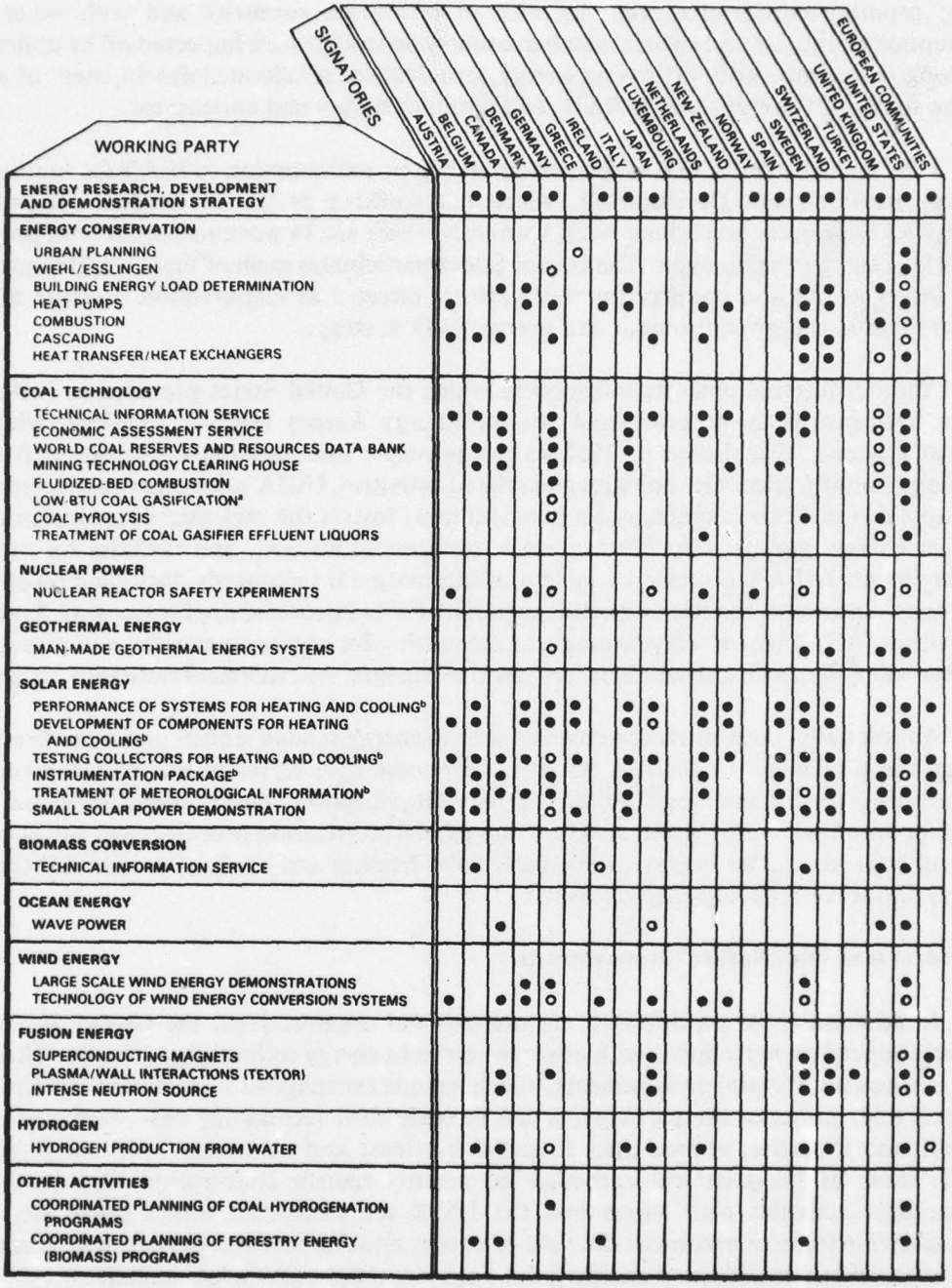
Another international organization in which the United States participates (with 110 other countries) is the International Atomic Energy Agency (IAEA), affiliated with the United Nations. Established in 1957 as the principal international organization for the development of nuclear technologies and related activities, IAEA promotes the development and application of nuclear energy for peaceful uses, fosters the exchange of information on nuclear energy, and provides for materials, services, equipment, and facilities for nuclear development. IAEA has created a system of international safeguards, including on-site inspections, to prevent the use of nuclear materials for nonpeaceful applications. U.S. activities within IAEA involve safeguarding and accounting for nuclear materials, and promoting nuclear safety standards, scientific information exchanges, and technical assistance programs.

Additionally, the United States heads several energy-related studies under the Committee on the Challenges to Modern Society. This committee serves to maintain the energy-related programs of the North Atlantic Treaty Organization. These studies focus on fuel-efficient automotive propulsion systems; flue-gas desulfurization processes and sulfur-oxide control strategies; solar energy, particularly solar heating and cooling; geothermal energy; and methods for reducing energy losses.[6]

Bilateral and Multilateral Agreements

In addition to its participation in international organizations, the United States has signed cooperative agreements with other countries in energy technology activities. Through bilateral and multilateral arrangements, which include exchange of information and the conduct of joint projects, the participants can increase their technology base, technical manpower, and expertise; reduce their financial burdens; and accelerate technical progress. While most of the technical exchange agreements specify cooperation in a particular technology, activities with Japan and the USSR are conducted under broad umbrella arrangements for cooperation in the field of energy and the peaceful uses of atomic energy. The bilateral and multilateral energy technology exchange agreements include:

- Coal Research
  - — Definitive Agreement on Specific Projects in Coal Research (Poland).
  - — Agreement on Terms for Exchange of Information in Coal Technology (United Kingdom).



● Participation in project.
○ Operating agent.

[a]This project is not yet in an implementing agreement, and is covered by a statement of intent.

[b]These five projects are combined in the same implementing agreement.

Source: International Energy Agency of the Organization for Economic Cooperation and Development, "Annual Report on Energy Research, Development and Demonstration Activities of the IEA 1977-1978" (Paris, France, June 1978).

Figure A-2. INTERNATIONAL ENERGY AGENCY WORKING PARTY PROJECTS

- Geothermal Energy
  - — Arrangement to Exchange Information on the Utilization of Energy from Geothermal Sources (Iceland).
  - — Agreement Concerning Cooperative Information Exchange Relating to the Development of Geothermal Energy (Italy).
  - — Agreements on Cooperation in the Field of Geothermal Energy Research and Development (Italy, Mexico).
- Nuclear Energy
  - — Memorandum of Understanding in Nuclear Energy (Canada).
  - — Agreements in the Field of Liquid Metal-Cooled Fast Breeder Reactors (Federal Republic of Germany, France).
  - — Agreement on Cooperation in the Field of Radioactive Waste Management (Federal Republic of Germany).
  - — Agreement in the Field of Gas-Cooled Reactor Concepts and Technology (Federal Republic of Germany, France, Switzerland).
  - — Agreement on Fast Breeder Reactors (Japan).
  - — Memorandum on Cooperation in the Peaceful Uses of Atomic Energy (Romania).
  - — Agreement Concerning a Cooperative Program on Radioactive Waste Storage in Deep Geologic Formations (Sweden).
  - — Letter of Agreement on Collaboration in Controlled Thermonuclear Research (United Kingdom).
  - — Agreement on Cooperation in the Peaceful Uses of Atomic Energy (USSR).
- Solar Energy
  - — Memorandum of Understanding for Cooperation in Joint Research and Solar Thermal Conversion Systems (France).
  - — Memorandum of Understanding for Cooperation on Certain Safety Aspects of Solar Towers (France).
- Umbrella Agreements in the Field of Energy Research and Development
  - — Agreement on Cooperation in the Field of Energy Research and Development (solar and geothermal energy applications, storage batteries, coal liquefaction and gasification, energy applications of hydrogen technology, magnetohydrodynamics conversion, fuel cells, electrical energy transmission by superconduction of microwaves, advanced propulsion systems, energy conservation, utilization of waste materials and waste heat, and other areas of energy R&D as may be agreed) (Japan).
  - — Agreement on Cooperation in the Field of Energy (thermal power stations, hydroelectric power stations, heat-rejection systems, power plant pollution reduction, ultra-high voltage and high voltage direct current transmission technology, superconducting transmission technology, magnetohydrodynamics, solar energy, geothermal energy, oil technology, gas technology, and energy information and forecasting) (USSR).

U.S. Energy Policy Toward Developing Countries

The United States is formulating a coherent policy geared to the energy needs and goals of developing countries. This policy involves facilitating the transition from excessive and

costly dependence on imported petroleum to indigenous and alternative energy resources. This effort includes:

- *Less-Developed Country Program.* Coordinated by the Department of State and managed through DOE's Office of International Affairs, this program is concerned with evaluating overall national energy requirements and assessing both conventional and nonconventional energy options and needs for selected developing countries.
- *Section 119 of the International Development and Food Assistance Act Amendments of 1977 (P.L. 95-88),* entitled "Renewable and Unconventional Energy Technologies." P.L. 95-88 authorizes U.S. participation in "cooperative programs with developing countries in energy production and conservation, with particular emphasis on programs in research, development and use of small-scale decentralized renewable energy sources for rural areas . . ."
- *Title V of the Nuclear Non-Proliferation Act of 1978 (P.L. 95-248),* entitled "United States Assistance to Developing Countries." P.L. 95-248 commits the United States to the initiation of a comprehensive energy development program consisting of resource assessments, cooperative projects, and exchanges of scientists and energy experts.

REFERENCES

1. U.S. Department of Energy, "Department of Energy Organization and Functions Fact Book," September 1977.

2. U.S. Congress, House, Subcommittee on the Department of Interior and Related Agencies, Committee on Appropriations, *Department of the Interior and Related Agencies Appropriations for 1979,* 95th Cong., 2nd sess., Part 2, pp. 440-780.

3. U.S. Department of Energy, "Supplement to the U.S. Government Manual," September 1978.

4. U.S. Department of Energy, "International Bilateral and Multilateral Arrangements in Energy Technologies," DOE/IA-0001, July 1978.

5. Organization for Economic Cooperation and Development, *International Energy Agency Energy Policies and Programmes of IEA Countries,* 1977 Review (Paris, 1978).

6. "Aspects of NATO. The Challenges of Modern Society" (Brussels: NATO Information Service).

APPENDIX B
ENERGY CONVERSION FACTORS

APPENDIX B—ENERGY CONVERSION FACTORS

The rapid growth in energy research during the 1970s brought into sharp focus the problem of comparability of energy sources on a global basis. The paucity of adequate or reliable data was made worse by the usage of many different units of measurement and lack of a standardized methodology. Qualitative information about different or even similar energy sources was inadequate and there was little agreement on means of converting these sources to a common base. Meaningful research could only be undertaken with the assistance of a multitude of often confusing conversion tables.

The International System of Units, established by international agreement, was in part a response to the problem of conversion. Basically a modernized version of the metric system, it provides a logical and interconnected framework for all measurements in science, industry, and commerce. Since the system was first implemented, more than 50 units of measure in use throughout the world have been declared to be obsolete, to be used for a limited time, or to be replaced by units of the system itself.

Officially abbreviated SI, the system is built upon a foundation of seven base units, plus two supplementary units, which are listed in Table B-1. Each basic unit can be expressed in a factor of 10 as indicated in Table B-2, which also shows the corresponding prefix and symbol.

Table B-1. SI BASE AND SUPPLEMENTARY UNITS

Quantity	Name	Symbol
Base Units		
Length	meter	m
Mass	kilogram	kg
Time	second	s
Electric current	ampere	A
Thermodynamic temperature	kelvin	K
Amount of substance	mole	mol
Luminous intensity	candela	cd
Supplementary units		
Plane angle	radian	rad
Solid angle	steradian	sr

Source: U.S. Department of Energy, "The U.S. Department of Energy Guide to Selected Metric (SI) Units and Symbols," DOE/EIA-0038, April 1978.

Table B-2. SI EXPONENTIAL FACTORS

Factor	Prefix	Symbol
10^{18}	exa	E
10^{15}	peta	P
10^{12}	tera	T
10^{9}	giga	G
10^{6}	mega	M
10^{3}	kilo	k
10^{2}	hecto	h
10^{1}	deka	da
10^{-1}	deci	d
10^{-2}	centi	c
10^{-3}	milli	m
10^{-6}	micro	μ
10^{-9}	nano	n
10^{-12}	pico	p
10^{-15}	femto	f
10^{-18}	atto	a

Source: U.S. Department of Energy, "The U.S. Department of Energy Guide to Selected Metric (SI) Units and Symbols," DOE/EIA-0038, April 1978.

Until a comprehensive global system of energy measurement is implemented fully and a common energy base is established, the need for conversion tables will continue. The conversion factors provided in Table B-3 can be used to convert base units (length, mass) and some of the derived units (area, volume, pressure, energy, and power) to metric or SI units and vice versa. Table B-4 is an energy conversion chart.

Table B-3. SELECTED CONVERSION FACTORS

To convert from	To	Multiply by
Acres	Hectares	0.40468564
	Square feet	43560
	Square kilometers	0.0040468564
	Square meters	4046.8564
	Square miles	0.0015625
Atmospheres	Bars	1.01325
	Inches of Hg (32°F)	29.9213
	Kilograms/square centimeter	1.03323
	Millimeters of Hg (0°C)	760
	Newtons/square meter	101320
	Pounds/square inch	14.6960
Barrels (petroleum, U.S.)	Cubic feet	5.614583
	Cubic meters	0.15898
	Gallons (U.S.)	42
	Liters	158.98284
Bars	Atmospheres	0.986923
	Inches of Hg (32°F)	29.5300
	Kilograms/square centimeter	1.019716
	Newtons/square meter	100,000
	Pounds/square inch	14.5038
Btu	Btu (IST)[a]	0.999346
	Calories, gram (IST)	251.831
	Foot-pounds	777.649
	Horsepower-hours	0.000392752
	Joules	1054.35
	Joules (international)	1054.18
	Kilowatt-hours	0.000292875
	Kilowatt-hours (international)	0.000292827
	Tons of refrigeration (U.S. standard)	3.46995×10^{-3}
Btu (IST)	Btu	1.00065
Calories, gram[b]	Btu	0.0039683207
	Btu (IST)	0.00396573
	Calories, gram (IST)	0.999346
	Foot-pounds	3.08596
	Horsepower-hours	1.55857×10^{-6}
	Joules	4.184
	Joules (international)	4.18331
	Kilowatt-hours	1.162222×10^{-6}
Centimeters	Feet	0.032808399
	Inches	0.39370079
	Meters	0.01
	Microns	10000
	Millimeters	10
	Millimicrons	1×10^{7}
Cubic centimeters	Cubic feet	3.5314667×10^{-5}
	Cubic inches	0.061023744
	Cubic meters	1×10^{-6}
	Gallons (liquid, U.S.)	0.00026417205
	Liters	0.000999972
Cubic feet	Barrels (petroleum, U.S.)	0.17811
	Cubic centimeters	28316.847
	Cubic meters	0.028316847

Table B-3. SELECTED CONVERSION FACTORS (CONT'D)

To convert from	To	Multiply by
Cubic feet (continued)	Gallons (liquid, U.S.)	7.4805195
	Liters	28.31605
Cubic inches	Cubic centimeters	16.387064
	Cubic feet	0.00057870370
	Gallons (liquid, U.S.)	0.0043290043
	Liters	0.01638661
Cubic meters	Barrels (liquid, U.S.)	8.3864145
	Barrels (petroleum, U.S.)	6.2900
	Cubic centimeters	1×10^6
	Cubic feet	35.314667
	Cubic inches	61023.74
	Gallons (liquid, U.S.)	264.17205
	Liters	999.972
	Tons (long, petroleum)	0.849
	Tons (metric, petroleum)	0.863
	Tons (short, petroleum)	0.957
Feet	Centimeters	30.48
	Inches	12
	Meters	0.3048
	Microns	304800
	Miles (statute)	0.000189393
Foot-pounds	Btu (IST)	0.00128509
	Calories, gram (IST)	0.323836
	Horsepower-hours	5.05050×10^{-7}
	Joules	1.35582
	Kilowatt-hours	3.76616×10^{-7}
Gallons (liquid, U.S.)	Barrels (liquid, U.S.)	0.031746032
	Barrels (petroleum, U.S.)	0.023809524
	Cubic centimeters	3785.4118
	Cubic feet	0.133680555
	Cubic inches	231
	Cubic meters	0.0037854118
	Liters	3.785306
	Tons (long, petroleum)	0.00319
	Tons (metric, petroleum)	0.00325
	Tons (short, petroleum)	0.00358
Hectares	Acres	2.4710538
	Square centimeters	1×10^8
	Square feet	107639.10
	Square kilometers	0.01
	Square meters	10000
	Square miles	0.0038610216
Horsepower-hours	Btu	2546.14
	Btu (IST)	2544.47
	Calories, gram (IST)	641196
	Foot-pounds	1.98×10^6
	Joules	2.68452×10^6
	Kilowatt-hours	0.745700
Inches	Centimeters	2.54
	Feet	0.083333
	Meters	0.0254

Table B-3. SELECTED CONVERSION FACTORS (CONT'D)

To convert from	To	Multiply by
Inches of Hg (32°F)	Atmospheres	0.0334211
	Bars	0.0338639
	Kilograms/square meter	345.316
	Millimeters of Hg (60°C)	25.4
	Newtons/square meter	3386.5
	Pounds/square inch	0.49115
Joules (absolute)	Btu (IST)	0.000947831
	Calories, gram (IST)	0.238849
	Ergs	1×10^{7}
	Foot-pounds	0.737562
	Horsepower-hours	3.72506×10^{-7}
	Joules (international)	0.999835
	Kilowatt-hours	2.7777×10^{-7}
Kilograms	Pounds (avoirdupois)	2.2046226
	Tons (long)	0.00098420653
	Tons (metric)	0.001
	Tons (short)	0.0011023113
Kilograms/square meter	Atmospheres	9.67841×10^{-5}
	Bars	9.80665×10^{-5}
	Inches of Hg (32°F)	0.0028959
	Millimeters of Hg (0°C)	0.0735559
	Pounds/square inch	0.0014223343
Kilometers	Centimeters	100000
	Feet	3280.8399
	Meters	1000
	Miles (statute)	0.62137119
Kilowatt-hours	Foot-pounds	2.65522×10^{6}
	Horsepower-hours	1.34102
	Joules	3.6×10^{6}
Kilowatt-hours (international)	Btu	3412.7
	Calories, gram (IST)	860000
	Foot-pounds	2.65566×10^{6}
	Horsepower-hours	1.34124
	Joules	3.60059×10^{6}
	Joules (international)	3.6×10^{6}
Liters	Barrels (petroleum, U.S.)	0.00629
	Cubic centimeters	1000.028
	Cubic feet	0.03531566
	Cubic inches	61.02545
	Cubic meters	0.001000028
	Gallons (liquid, U.S.)	0.2641794
Meters	Centimeters	100
	Feet	3.2808399
	Inches	39.370079
	Kilometers	0.001
	Miles (statute)	0.00062137119
	Millimeters	1000
	Millimicrons	1×10^{9}
Mhos	$Ohms^{-1}$	1
	Siemen's units	1

Table B-3. SELECTED CONVERSION FACTORS (CONT'D)

To convert from	To	Multiply by
Microns	Centimeters	0.0001
	Inches	3.9370079×10^{-5}
	Millimeters	0.001
	Millimicrons	1000
Miles (statute)	Feet	5280
	Kilometers	1.609344
	Meters	1609.344
Miles/hour	Centimeters/second	44.704
	Feet/hour	5280
	Feet/minute	88
	Kilometers/hour	1.609344
	Meters/second	0.44704
Millimeters of Hg (0°C)	Atmospheres	0.0013157895
	Bars	0.00133322
	Inches of Hg (32°F)	0.039370
	Kilograms/square meter	13.5951
	Newtons/square meter	133.32
	Pounds/square inch	0.0193368
Millimicrons	Centimeters	1×10^{-7}
	Inches	3.9370079×10^{-8}
	Microns	0.001
	Millimeters	1×10^{-6}
Newtons/square meter	Atmospheres	0.0000098692
	Bars	0.00001
	Inches of Hg (32°F)	0.0002953
	Millimeters of Hg (0°C)	0.007506
	Pounds/square inch	0.00014504
Pounds (avoirdupois)	Grams	453.59237
	Kilograms	0.45359237
	Ounces (avoirdupois)	16
	Tons (long)	0.00044642857
	Tons (metric)	0.00045359237
	Tons (short)	0.0005
Pounds/square inch	Atmospheres	0.0680460
	Bars	0.0689476
	Inches of Hg (32°F)	2.03602
	Kilograms/square centimeter	0.070306958
	Millimeters of Hg (0°C)	51.7149
	Newtons/square meter	6894.9
Square centimeters	Square feet	0.0010763910
	Square inches	0.15500031
	Square meters	0.0001
	Square millimeters	100
Square feet	Acres	2.295684×10^{-5}
	Square centimeters	929.0304
	Square inches	144
	Square meters	0.09290304
	Square miles	3.5870064×10^{-8}
Square inches	Square centimeters	6.4516
	Square feet	0.0069444
	Square meters	0.00064516

Table B-3. SELECTED CONVERSION FACTORS (CONT'D)

To convert from	To	Multiply by
Square inches (continued)	Square millimeters	645.16
Square kilometers	Acres	247.10538
	Hectares	100
	Square feet	1.0763910×10^7
	Square meters	1×10^6
	Square miles	0.38610216
Square meters	Hectares	0.0001
	Square centimeters	10000
	Square feet	10.763910
	Square inches	1550.0031
Square miles	Acres	640
	Hectares	258.99881
	Square feet	2.7878288×10^7
	Square kilometers	2.5899881
	Square meters	2589988.1
Tons (long)	Barrels (petroleum, U.S.)	7.45
	Kilograms	1016.0469
	Pounds (avoirdupois)	2240
	Tons (metric)	1.0160469
	Tons (short)	1.12
Tons (metric)	Barrels (petroleum, U.S.)	7.33
	Kilograms	1000
	Pounds (avoirdupois)	2204.6226
	Tons (long)	0.98420653
	Tons (short)	1.1023113
Tons (short)	Barrels (petroleum, U.S.)	6.65
	Kilograms	907.18474
	Pounds (avoirdupois)	2000
	Tons (long)	0.89285714
	Tons (metric)	0.90718474
Tons of refrigeration (standard, U.S.)	Btu (IST)	288000

[a]IST—International Steam Table.

[b]This is the calorie as defined by the U.S. National Bureau of Standards and is equal to 4.18400 joules.

Table B-4. ENERGY CONVERSION CHART[a]

Thermal Energy (Btu)	Oil (Barrels)[b]	Natural Gas (1,000 cubic feet)	Coal (Short Tons)	Nuclear (Grams U-235)	Water (Millions of gallons falling 100 feet)	Electricity (kWh)[c]
1.0	0.00000017	0.00000095	0.000000038	0.000000013	0.00000093	0.00010
5,800,000	1.0	5.5	0.22	0.077	5.4	560
1,100,000	0.18	1.0	0.040	0.014	0.98	100
26,000,000	4.5	25	1.0	0.35	24	2,500
75,000,000	13.0	72	2.9	1.0	70	7,300
1,100,000	0.19	1.0	0.041	0.014	1.0	100
10,000	0.0018	0.0099	0.00040	0.00014	0.0096	1.0

[a]Values rounded to two significant figures. For example, given that a 1,000 MW power plant operates for 1 day, how much oil is consumed? (1,000 MW) × (1,000 kW/MW) × (24 hours/day) × (0.0018 bbl/kWh) = 43,000 bbl of oil. How much U-235 is consumed? (1,000 MW) × (1,000 kW/MW) × (24 hours/day) × (0.00014 g U-235/kWh) = 3.300 g of U-235.

[b]1 barrel of oil = 42 gallons.

[c]A conversion efficiency from heat to electricity of 0.33 is assumed.

Source: American Nuclear Society, "Nuclear Power and the Environment," April 1976.

